Colorado Department of Public Health and Environment

OPERATING PERMIT

Suncor Energy (U.S.A.)
Commerce City Refinery, Plant 2 (East)

Issued: October 1, 2006
Last Revised: June 15, 2009

AIR POLLUTION CONTROL DIVISION
COLORADO OPERATING PERMIT

FACILITY NAME:	Suncor Energy (U.S.A.) Inc.	OPERATING PERMIT NUMBER
FACILITY ID:	0010003	**95OPAD108**
ISSUE DATE:	October 1, 2006	
EXPIRATION DATE:	October 1, 2011	
MODIFICATIONS:	See Appendix F of Permit	

Issued in accordance with the provisions of Colorado Air Pollution Prevention and Control Act, 25-7-101 et seq. and applicable rules and regulations.

ISSUED TO:	PLANT SITE LOCATION:
Suncor Energy (U.S.A.) Inc. 5801 Brighton Blvd. Commerce City, CO 80022	5800 Brighton Blvd. Commerce City, CO 80022

INFORMATION RELIED UPON

Operating Permit Application Received:	December 19, 1995 revised December 20, 1999
And Additional Information Received:	

Nature of Business:	Petroleum Refining
Primary SIC:	2911

RESPONSIBLE OFFICIAL		FACILITY CONTACT PERSON	
Name:	John Gallagher	Name:	Jay Christopher
Title:	Vice President, Refining and Pipelines	Title:	Environmental Manager
Phone:	(303) 286-5788	Phone	(303) 286-5731

SUBMITTAL DEADLINES

Semi-Annual Monitoring Period:	July 1 – December 31, January 1 – June 30
Semi-Annual Monitoring Report:	March 1, 2007 and September 1, 2007 and subsequent years
Annual Compliance Period:	July 1 – June 30
Annual Compliance Certification:	September 1, 2007 and subsequent years

Note that the Semi-Annual Monitoring reports and the Annual Compliance report must be received at the Division office by 5:00 p.m. on the due date. Postmarked dates will not be accepted for the purposes of determining the timely receipt of those reports.

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SECTION I - General Activities and Summary

1. Permitted Activities

1.1 This facility is a petroleum refinery.

1.2 The facility is located at 5800 Brighton Boulevard, Commerce City, which is within the Denver metro area. The Denver metro area is classified as attainment/maintenance for carbon monoxide and particulate matter less than 10 microns (PM_{10}). Under that classification, all SIP-approved requirements for CO and PM_{10} will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act. The Denver metro area is classified as non-attainment for ozone and is part of the 8-hour Ozone Control Area as defined in Regulation No. 7, Section II.A.1.

There are no affected states within 50 miles of the plant. Rocky Mountain National Park is a Federal Class I designated area within 100 kilometers of the plant.

1.3 Until such time as this permit expires or is modified or revoked, the permittee is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.4 This Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this Operating Permit and shall survive reissuance. Any requirements that were designated in the Colorado Refinery Company and TPI Petroleum Inc. Consent Decree (No. 99-1759) filed September 8, 1999 and the Valero Consent Decree (No. SA-05-CA-0569) entered November 23, 2005 as applicable requirements have been incorporated into this operating permit and shall survive reissuance as applicable requirements. This Operating Permit incorporates the applicable requirements (except as noted in Section II) from the following Colorado Construction Permit(s): 12AD032(1-4), 11AD250, 89AD126, 87AD184, 89AD031, 95AD1073(1-5), 93AD306, 88AD289(1-2), 93AD763, 98AD0758, 99AD0941, 88AD134, 93AD592, 11AD251, 00AD0183, and a PSD permit issued by the EPA on December 12, 1986.

1.5 All conditions in this permit are enforceable by US Environmental Protection Agency, Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II – Conditions 19.4 (opacity), 20.2 (PM emission limit), and 22.2 (SO_2 emission limit); Section IV – Conditions 3.d, 3.g (last paragraph), 14 and 18 (as noted).

1.6 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section IV of this permit.

2. Alternative Operating Scenarios

2.1 The permittee shall be allowed to make the following changes to its method of operation without applying for a revision of this permit.

2.1.1 No separate operating scenarios have been specified.

3. Nonattainment Area New Source Review (NANSR) and Prevention Of Significant Deterioration (PSD)

3.1 This facility is categorized as a NANSR major stationary source for ozone (Potential to Emit of NO_X and VOC $\geq$100 tons/year). Future modifications at this facility resulting in a significant net emissions increase (see Regulation No. 3, Part D, Sections II.A.26 and 42) for VOC or NO_X or a modification which is major by itself (Potential to Emit $\geq$ 100 tons/year or either VOC or NO_X) may result in the application of the NANSR review requirements.

3.2 This source is categorized as a PSD major stationary source (Potential to Emit $\geq$ 100 tons/year) for PM, PM_{10}, SO_2, NO_X and CO. Future modifications at this facility resulting in a significant net emissions increase (see Regulation No. 3, Part D, Sections II.A.26 and 42) or a modification that is major by itself (Potential to Emit $\geq$ 100 tons/yr) for any pollutant listed in Regulation No. 3, Part D, Section II.A.42 for which the area is in attainment or attainment/maintenance may result in the application of the PSD review requirements.

3.3 The following Operating Permit is associated with this facility for purposes of determining applicability of NANSR and PSD regulations: 96OPAD120 for Suncor Energy (U.S.A.) (West Plant).

4. Accidental Release Prevention Program (112(r))

4.1 Based on information supplied by the applicant, this facility is subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act).

5. Summary of Emission Units

5.1 The emissions units regulated by this permit are the following:

Emission Unit Number	AIRS Stack Number	Description	Pollution Control Device	Construction Permit
P001		**Crude Distillation Unit**		
B001	206	Crude Heater – OPF, S/N: 5450-1240, refinery fuel gas fired heater, design rate: 153 mmBtu/hour	Low-NO_X Burners	12AD032-1
B010	295	Vacuum Heater – PetroChem., S/N: 86-F-1497, refinery fuel gas fired heater, design rate: 31 mmBtu/hour	Low – NOx Combustion System	12AD032-1
P003		**Fluid Catalytic Cracking Unit**		
B002	205	Preheater, Petrochem, Model C-61145, (formally crude oil heater) rated at 59.44 mmBtu/hour	Low-NO_X Burners	11AD250
P004	217	Regenerator	N/A	
P014		Catalyst Handling	N/A	
P013, P005		**Naphtha Hydrotreater (P013) and Reformer Unit (P005)**		
B003	208	Heater 1 – John Zink, Drg. No.:B-Y 11673, S/N: 099274-1, refinery fuel gas fired preheater rated at 64.4 mmBtu/hour	Low-NO_X Burners	12AD032-4
B004	208	Heater 2 – John Zinc, Drg. No.: B-Y 11674, S/N: 099274-2, refinery fuel gas fired preheater rated at 64.4 mmBtu/hour	Low-NO_X Burners	12AD032-4
B005	208	Heater 3 – John Zink, Drg. No.: B-y 11675, S/N: 099274-3, refinery fuel gas fired preheater rated at 32.2 mmBtu/hour	Low-NO_X Burners	12AD032-4
P006		**Polymerization Unit**		
P007		**Gas Plant**		
F012	280	Equipment Leaks from Saturated Gas Plant, Storage Facility associated with Saturated Gas Plant, and Unsaturated Gas Plant	Leak Detection and Repair	89AD126
		Sulfur Recovery Plant		
P009	220	Sulfur Recovery Plant – Three-Stage Claus sulfur recovery system, 30 mmscf/day acid gas feed, sulfur recovery of 4.5 tons (4.0 long tons) per day – 1.95 mmBtu/hour tail gas incinerator	Tail Gas Incinerator	12AD032-3

Emission Unit Number	AIRS Stack Number	Description	Pollution Control Device	Construction Permit
		Utilities		
B006	291	Nebraska Boiler, Model 81-832-5, S/N: 98842, rated at 75 mmBtu/hour	Low-NO_X Burners	87AD184
B007	202	Nebraska Boiler, Model NS-E-59, S/N: D-2324, rated at 75 mmBtu/hour	N/A	
B008	202	Nebraska Boiler, Model NS-E-61, S/N: 202011, rated at 75 mmBtu/hour	N/A	
P011		Cooling Tower	N/A	Exempt
F015, F016, F017, F024		**Crude Unloading/Gasoline Truck Tank Loading Docks**		
F024	204	Four (4) Custom, bottom loading truck loading docks for transfer of petroleum products into tanker trucks. Docks A, B, C and D	Vapor Capture System Knock Out Drum Flare	11AD251
F016	290	One Custom unloading rack for crude oil unloading – Old Crude Unloading Rack (North) and associated fugitive emissions from equipment leaks	Leak Detection and Repair	93AD592
F015	293	One Custom unloading rack for crude oil unloading – New Crude Oil Unloading Rack (South) and associated fugitive emissions from equipment leaks		
C005		**Flare**		
	279	Refinery Process Blowdown, Equipment leaks from pumps associated with knock out drum, One John Zink refinery flare	N/A	88AD134
		LPG Storage, Truck, and Railcar Facility		
F019	284	One Custom railcar loading dock for loading LPG, equipped with four loading arms	Vapor Collection System Flare	89AD031
		One Custom railcar loading dock for loading petroleum products, equipped with four loading arms		
F020		One Custom truck loading dock for loading of LPG, equipped with three loading arms		
T066, T067, T068, T069		Four LPG storage tanks, 57,582 gallons capacity each		
T050, T051, T060, T061, T063, T064		Six storage tanks		Grandfathered
F021		**Wastewater Treatment System**		
F021	294	Upper API	Cover and Oil Recovery System	Grandfathered
F022	283	One “Middle” oil/water separator rated to treat 250,000,000 gallons/day of water		95AD1073-5
F023	294	Lower API		Grandfathered
F025		Sour Water Stripper Sewers		Grandfathered

Emission Unit Number	AIRS Stack Number	Description	Pollution Control Device	Construction Permit
		Black Oil Heater		
B009	292	Refinery fuel gas (primary fuel)/natural gas or propane (secondary fuel) fired burner for heating of black oil in the tank farm, rated at 8.1 mmBtu/hour	N/A	95AD1073-4
		Tank Farms		
		Group B Tanks – Grandfathered Internal Floating Roof Tanks		
T010	226	2,263,884 gallons capacity for storage of petroleum feed or petroleum product	Designed and operated to minimize emissions	Grandfathered
T011	227	2,056,026 gallons capacity for storage of petroleum feed or petroleum product		
T027	242	2,302,524 gallons capacity for storage of petroleum feed or petroleum product		
T030	246	2,270,856 gallons capacity for storage of petroleum feed or petroleum product		
T040	255	289,800 gallons capacity for storage of petroleum feed or petroleum product		
T041	256	307,944 gallons capacity for storage of petroleum feed or petroleum product		
		Group C Tanks – Grandfathered, Fixed Roof Storing Exempted Materials		
T008	224	1,024,590 gallons capacity for storage of heavy petroleum product	Designed and operated to minimize emissions	Grandfathered
T009	225	1,012,536 gallons capacity for storage of heavy petroleum product		
T042	257	307,818 gallons capacity for storage of heavy petroleum product		
T043	258	302,694 gallons capacity for storage of heavy petroleum product		
T045	260	420,798 gallons capacity for storage of heavy petroleum product		
T048	261	419,748 gallons capacity for storage of heavy petroleum product		
T049	262	421,344 gallons capacity for storage of heavy petroleum product		
T057	270	1,666,560 gallons capacity for storage of heavy petroleum product		

Emission Unit Number	AIRS Stack Number	Description	Pollution Control Device	Construction Permit
		Group D Tanks – Grandfathered, Fixed Roof Vapor Pressure <0.65 psia		
T004	221	99,120 gallons capacity for storage of heavy petroleum product	Designed and operated to minimize emissions	Grandfathered
T005	222	97,902 gallons capacity for storage of heavy petroleum product		
T031	247	2,079,243 gallons capacity for storage of heavy petroleum product		
T039	254	2,203,320 gallons capacity for storage of heavy petroleum product		
T055	268	406,602 gallons capacity for storage of heavy petroleum product		
T056	269	410,508 gallons capacity for storage of heavy petroleum product		
		Group E Tanks – Tanks with Unique Requirements		
T006	223	Internal Floating Roof Tank No.6 – 8,431,920 gallons capacity for the storage of petroleum products	Designed and operated to minimize emissions	95AD1073-1
T012	228	External Floating Roof Tank No. 12 – 357,336 gallons capacity for storage of petroleum feed or petroleum products		Grandfathered
T020	234	Internal Floating Roof Tank No. 20 – 840,000 gallons capacity for storage of off-specification products		93AD306
T024	238	4,933 barrel capacity for storing gasoline or lower vapor pressure petroleum liquids		00AD0183
T026	240	External Floating Roof Tank No. 26 – 2,347,800 gallons capacity for storage of crude oil or heavier petroleum product		99AD0941
T038	253	External Floating Roof Tank No. 38 – 2,051,364 gallons capacity for storage of petroleum feed or petroleum products		Grandfathered
T046	281	Fixed Roof Tank No. 46 – 14,000 barrel capacity for storage of fuel oil or heavier petroleum product		88AD289-1
T047	282	External Floating Roof Tank No 47 – 1,320,000 gallons capacity for storage of gasoline with a RVP of 10 or heavier petroleum product		88AD289-2
T053	266	Internal Floating Roof Tank No. 53 – 450,000 gallons capacity for storage of petroleum products		95AD1073-3
T062	290	Internal Floating Roof Tank No. 62, - 1,512,000 gallons capacity for storage of various petroleum products		93AD763

Emission Unit Number	AIRS Stack Number	Description	Pollution Control Device	Construction Permit
T079	306	5,040,000 gallons capacity for storage of gas oil or heavier petroleum products	Designed and operated to minimize emissions	
		Group F – Grandfathered, External Floating Roof Tanks		
T035	250	372,456 gallons capacity for storage of petroleum feed or petroleum products	Designed and operated to minimize emissions	Grandfathered
T036	251	377,076 gallons capacity for storage of petroleum feed or petroleum products		
T044	259	350,490 gallons capacity for storage of petroleum feed or petroleum products		
T052	265	364,602 gallons capacity for storage of petroleum feed or petroleum products		
T054	267	364,518 gallons capacity for storage of petroleum feed or petroleum products		
		Group G Tanks – Grandfathered, Internal Floating Roof		
T025	239	177,030 gallons capacity for storage of petroleum feed or petroleum products		
T028	243	Internal Floating Roof Tank No. 28 – 2,203,866 gallons capacity for storage of gasoline or heavier petroleum product		
T037	252	969,360 gallons capacity for storage of petroleum feed or petroleum products		
T058	271	993,510 gallons capacity for storage of petroleum feed or petroleum products		
		Aboveground Piping Project **Second Stage of Crude Oil Desalting Unit**		
	297	Equipment leaks from components installed as part of piping modification in the petroleum products handling system and the second stage of the desalter	Leak Detection and Repair Program	98AD0758
F031	307	Equipment leaks from installation of Tank T079	Leak Detection and Repair Program	

6. Compliance Assurance Monitoring (CAM)

6.1 The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have pre-control emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program set forth in 40 CFR Part 64 as adopted by reference into Colorado Regulation No. 3, Part C, Section XIV:

Since the Title V Permit Application for this facility was determined to be administratively complete prior to April 15, 1998 and there have been no significant modifications made to any large pollutant specific emission units after April 15, 1998, the compliance assurance monitoring requirements do not apply at this time.

SECTION II - Specific Permit Terms

1. Crude Distillation Unit – P001; B001 – Crude Heater; B010 – Vacuum Heater

Parameter	Permit Condition Number	Limitation	Emission Factor[1]	Monitoring Method	Monitoring Interval
PM	1.1	Crude Heater: 2.92 tons/year	Crude: 7.6 lbs/mmscf Vacuum: 0.01 lb/mmBtu	Recordkeeping Calculation	Monthly
	1.2	See Conditions 20.1 and 20.2		Fuel Type	N/A
PM_{10}	1.1	Crude Heater: 2.92 tons/year	Crude: 7.6 lbs/mmscf Vacuum: 0.01 lb/mmBtu	Recordkeeping Calculation	Monthly
SO_2	1.1	Crude Heater: 17.30 tons/year Vacuum Heater: 6.13 tons/year	Per Appendix H		
	1.3	Fuel gas shall not contain H_2S in excess of 0.10 gr/scf		Continuous Emission Monitor	Continuous per 60.13
	1.4	0.3 lb SO_2/bbl of oil processed **(State-Only)**	Per Appendix H	Recordkeeping Calculation	Daily Annually
		0.3 lb SO_2/bbl/day of oil processed			Daily Monthly
NO_x	1.1	Crude Heater: 32.76 tons/year Vacuum Heater: 10.18 tons/year	Crude: 85 lbs/mmscf Vacuum: 0.075 lb/mmBtu	Recordkeeping Calculation	Monthly
VOC		Crude Heater: 2.12 tons/year	Crude and Vacuum: 5.5 lbs/mmscf		
CO		Crude Heater: 32.37 tons/year Vacuum Heater: 5.43 tons/year	Crude: 84 lbs/mmscf Vacuum: 0.04 lb/mmBtu		
Heat Input	1.5	Crude Heater: 770,880,000,000 Btu/year Vacuum Heater: 271,560,000,000 Btu/year		Recordkeeping	Monthly
Equipment Leaks	1.6	Leak detection and repair program		Inspection See 40 CFR Part 63 Subpart CC and 40 CFR Part 60 Subpart GGG, Conditions 30 and 32	

Parameter	Permit Condition Number	Limitation	Emission Factor[1]	Monitoring	
				Method	Interval
Opacity	1.7	Not to exceed 20%, except as provided for below		Fuel Type	
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			

[1]AP-42 emission factors for fuel burning equipment throughout this permit should be corrected for BTU content

1.1 Emissions of air pollutants shall not exceed the limits listed above. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. The permit holder shall calculate monthly and rolling twelve month emissions using the emission factors listed above and the annual fuel usage in the following equation. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculations of emissions shall be based on the most recent Btu and sulfur analyses. The permittee shall keep a compliance record on site for Division review. (Construction Permit 12AD032-1, revised per Section I, Condition 1.4 of this permit, to reflect revised emission factors.)

For APEN reporting and fee purposes, annual emissions shall be calculated using the emission factors listed above and the annual fuel usage in the following equation. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculation of emissions shall be based on the most recent Btu and sulfur analyses.

Vacuum Heater PM/PM_{10} Emissions (Tons/year) = [EF (lbs/mmBtu) x fuel usage (mmBtu/year)]/2000(lbs/ton)

Other Emissions Except SO_2 Emissions (Tons/year) = [EF (lbs/mmscf) x fuel usage (mmscf/year) x Btu correction]/2000(lbs/ton)

1.2 These sources are subject to the particulate matter emission limits set forth in Conditions 20.1 and 20.2 of this permit.

1.3 The crude heater (B001) and Vacuum Heater (B010) are subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 22.5 of this permit.

1.4 Sulfur dioxide emissions from these sources shall be included when evaluating compliance with the Colorado Regulations No. 1 and No. 6, Part B emission limits set forth in Conditions 22.1 and 22.2 of this permit.

1.5 The heat input shall not exceed the limit listed in the table above. (Construction Permit 12AD032-1) Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Monthly records of the actual consumption rate shall be maintained by the applicant and made available to the Division for inspection upon request.

A flow device is used to monitor fuel use. Fuel use shall be converted to Btu use using the most recent heat value analysis. In the event that the flow device becomes inoperable, fuel use data shall be obtained from the Refinery Yields data system (an internal material balance and accounting system). If, after review, the Yields system is determined by Suncor to not provide sufficient or accurate daily fuel use data, the maximum-fired duty for the fired source will be conservatively assumed. Data will be utilized to calculate a 12-month rolling total usage.

Fuel Sampling

The refinery fuel gas shall be analyzed at least once per week for heat value.

Records of the 12-month rolling total fuel use, and fuel heating value analyses shall be maintained and made available for inspection upon request.

1.6 Equipment leak emissions associated with the Crude Unit (F001) are subject to the requirements of 40 CFR Part 60, Subpart GGG and 40 CFR Part 63, Subpart CC, as set forth in Conditions 30 and 32 of this permit.

1.7 These sources are subject to the opacity limits set forth in Conditions19.1, 19.2, and 19.4 of this permit.

2. Fluid Catalytic Cracking Unit (FCCU) – P003; B002 – Preheater; P004 – Reactor-Regenerator; P014 – Catalyst Handling

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	2.1	B002: 1.9 tons/yr	B002: 7.45 x 10^{-3} lb/MMBtu P004: 103.04 lbs/Mbbl fresh feed P014: 0.0024 lb/ton loaded	Recordkeeping Calculation	Monthly
	2.3	B002 : See Condition 20.1		Fuel Type	
	2.4	P004 & P014: See Condition 21.1	P004: 103.04 lbs/Mbbl fresh feed P014: 0.0024 lb/ton loaded	Recordkeeping Calculation	Monthly

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring Method	Monitoring Interval
PM_{10}	2.1	B002: 1.9 tons/yr	B002: 7.45 x 10^{-3} lb/MMBtu P004: 103.04 lbs/Mbbl fresh feed	Recordkeeping Calculation	Monthly
SO_2	2.1	B002: 7.0 tons/yr	B002: Per Appendix H P004: Per Appendix H	Recordkeeping Calculation	Daily Monthly Annually
	2.5	0.3 lb SO_2/bbl of oil processed (**State-Only**) 0.3 lb SO_2/bbl/day of oil processed	Per Appendix H		
	2.10	Fuel gas shall not contain H_2S in excess of 0.10 gr/scf		Continuous Emissions Monitor	Continuous per 60.13
SO_2 Monitor	2.9.			CEM	
NOx	2.1	B002: 23.2 tons/yr	B002: 0.089 lb/MMBtu P004: 27.18 lbs/Mbbl fresh feed	Recordkeeping Calculation	Monthly
VOC		B002: 1.4 tons/yr	B002: 5.29 x 10^{-3} lb/MMBtu P004: 7.48 lbs/Mbbl fresh feed		
CO		B002: 21.4 tons/yr	B002: 0.082 lb/MMBtu P004: CEM		
Fuel Use FCCU Fresh Feed Rate	2.2	B002: 520,694.4 MMBtu/yr		Recordkeeping	Monthly
Equipment Leaks	2.6	Leak detection and Repair program		Inspection See 40 CFR Part 63 Subpart CC, Condition 32	
MACT Standard	2.7	See Condition 2.7 (Effective April 11, 2005)			
B002: Case-by-Case MACT Requirements	2.12	Submit 112(j) Application by Deadline		See Condition 2.12	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Opacity	2.8	Not to exceed 20%, except as provided for below		B002: Fuel Use	N/A
				P004: COM	Continuous
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes		P014: Standard Operating Procedures Method 9	Semi-Annually

2.1 For P003, P004 and P014: For APEN reporting and fee purposes, annual emissions shall be calculated using the emission factors and methods listed in the table above, and described in this Condition. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculation of annual emissions shall be based on actual FCCU fresh feed rate, actual amount of catalyst loaded, and actual fuel consumption and the most recent Btu and sulfur analyses. (Colorado Regulation No. 3, Part A, Section II)

PM, PM_{10}, NOx and VOC emissions shall be estimated by using actual FCCU fresh feed for P004. PM, PM_{10}, NO_X, CO and VOC emissions shall be estimated using the actual amount of catalyst loaded for P014 and the following equations:

P004: Emissions (Tons/year) = [EF(lbs/mbbl fresh feed) x Feed rate (fresh feed (mbbl/year)]/2000 (lbs/ton)

P014: Emissions (Tons/Year) = [EF(lbs/ton loaded) x amount of catalyst loaded (tons/year)]/2000 (lbs/ton)

CO emissions from the P004 shall be estimated using a CEM. The CEM shall be maintained and operated in accordance with Colorado Regulation No. 1, Section IV.G.

For B002: Emissions for air pollutants shall not exceed the limits listed in the above table (as provided for under the provisions of Section I, Condition 1.4 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to limit emissions as indicated on the APEN submitted August 3, 2007). Compliance with the annual limits shall be determined on a rolling twelve (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. The permit holder shall calculate monthly and rolling twelve month emissions using the emission factors listed above and the annual fuel usage in the following equation. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculations of emissions shall be based on the most recent Btu and sulfur analyses. The permittee shall keep a compliance record on site for Division review.

B002: Emissions (Tons/Year) = [EF(lbs/MMBtu) x heat input (MMBtu/mo)]/2000 (lbs/ton)

2.2 The heat input from B002 shall not exceed the limit listed in the above table (as provided for under the provisions of Section I, Condition 1.4 and Colorado Regulation No. 3, Part B, Section

II.A.6 and Part C, Section X, to include throughput limits as indicated on the APEN submitted August 3, 2007). Compliance with the annual limits shall be determined on a rolling twelve (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data.

A flow device is used to monitor fuel use. Fuel use shall be converted to Btu using the most recent heat value analysis. In the event that the flow device becomes inoperable, fuel use data shall be obtained from the Refinery Yields data system (an internal material balance and accounting system). If, after review, the Yields system is determined by Suncor to not provide sufficient or accurate daily fuel use data, the maximum-fired duty for the fired source will be conservatively assumed. Data will be utilized to calculate a 12-month rolling total usage.

Fresh feed to the FCCU shall be tracked monthly and utilized to calculate a 12-month rolling total. Records of the monthly fuel use and FCCU feed rates shall be maintained and made available for inspection upon request.

Fuel Sampling

The refinery fuel gas shall be analyzed at least once per week for heat value.

Records of the 12-month rolling total fuel use, and fuel heating value analyses shall be maintained and made available for inspection upon request.

2.3 B002 is subject to the particulate matter emission limit set forth in Condition 20.1 of this permit.

2.4 P004 and P014 are subject to the particulate matter emission limit set forth in Condition 21.1 of this permit.

2.5 Sulfur dioxide emissions from the heater (B002) and regenerator (P004) shall be included when evaluating compliance with the Colorado Regulations No. 1 and 6, Part B emission limits set forth in Conditions 22.1 and 22.2 of this permit.

2.6 Equipment leak emissions associated with the FCCU (F002) are subject to the equipment leak requirements of 40 CFR Part 63, Subpart CC, as set forth in Condition 32 of this permit.

2.7 This source is subject to the provisions of 40 CFR Part 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, as set forth in Condition 33 of this permit.

2.8 The heater (B002), regenerator (P004), and catalyst handling (P014) sources are subject to the opacity limits set forth in Conditions 19.1 and 19.2 of this permit.

2.9 SO_2 emissions will be monitored by means of the continuous emission monitor (CEM) required by paragraph 90 of the Consent Decree (No. SA-05-CA-0569, entered November 23, 2005). The permittee shall install, certify, calibrate, maintain and operate all CEMS required by this paragraph in accordance with the provisions of 40 CFR § 60.13 (Conditions 36.7 through 36.10) that are applicable to CEMS (excluding those provisions applicable only to continuous opacity monitoring systems) and Part 60, Appendices A and F, and the applicable performance specification test of 40 CFR part 60 Appendix B. With respect to 40 CFR Part 60 Appendix F, in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the permittee shall conduce either a RAA or a RATA on the CEMS at least once every three (3) years. The permittee must also conduct a CGA each calendar quarter during which a RAA or a RATA is not performed. (Consent Decree No. SA-05-CA-0569, entered November 23, 2005, paragraph 90).

2.10 The FCCU pre-heater (B002) is subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 22.5 of this permit (Consent Decree, No. SA-05-CA-0569, entered November 23, 2005, paragraph 115).

2.11 No later than 180 days after installing controls on B002, the permittee shall complete an initial performance test of the source and any periodic tests that may be required by EPA or the Division. The pemittee shall report the results of the initial performance testing to the EPA and the Division. The permittee shall use Method 7E or an EPA-approved alternative test method to conduct initial performance testing required by this condition (Consent Decree, No. SA-05-CA-0569, entered November 23, 2005, paragraph 29).

2.12 The FCCU pre-heater (B002) falls under the Maximum Achievable Control Technology (MACT) source category of Industrial, Commercial and Institutional Boilers and Process Heaters. Since the MACT provisions for this source category (codified in 40 CFR Part 63 Subpart DDDDD) were vacated as of July 30, 2007, this unit will be subject to the case-by-case MACT determination requirements of 112(j) of the Clean Air Act Amendments (codified in 40 CFR Part 63 Subpart B §§ 63.50 through 63.56). The permittee shall submit a 112(j) application by the deadline specified by EPA. As of the issuance date of this permit, the deadline has not been set; however, the Division will notify the permittee of the deadline for the 112(j) application at a later date.

3. Naphtha Hydrotreater/Reformer - P005; B003 – Heater #1 (H401); B004 – Heater #2 (H402); B005 – Heater #3 (H403); F004 – Reactors (Catalyst Regeneration)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	3.1	5.4 tons/year	7.6 lbs/mmscf	Recordkeeping Calculation	Monthly
	3.2	See Conditions 20.1 and 20.2		Fuel Type	
PM_{10}	3.1	5.4 tons/year	7.6 lbs/mmscf	Recordkeeping	Monthly

<table>
<tr><th rowspan="2">Parameter</th><th rowspan="2">Permit Condition Number</th><th rowspan="2">Limitation</th><th rowspan="2">Emission Factor</th><th colspan="2">Monitoring</th></tr>
<tr><th>Method</th><th>Interval</th></tr>
<tr><td rowspan="4">SO_2</td><td>3.1</td><td>26.0 tons/year</td><td>Per Appendix H</td><td></td><td></td></tr>
<tr><td>3.3</td><td>Fuel gas shall not contain H_2S in excess of 0.10 gr/scf</td><td></td><td>Continuous Emission Monitor</td><td>Continuous per 60.13</td></tr>
<tr><td rowspan="2">3.4</td><td>0.3 lb SO2/bbl of oil processed (State-Only)</td><td rowspan="2">Per Appendix H</td><td rowspan="2">Recordkeeping
Calculation</td><td>Daily
Annually</td></tr>
<tr><td>0.3 lb SO_2/bbl/day of oil processed</td><td>Daily
Monthly</td></tr>
<tr><td>NOx</td><td rowspan="3">3.1</td><td>63.4 tons/year</td><td>0.075 lb/mmBTU</td><td rowspan="3">Recordkeeping
Calculation</td><td rowspan="3">Monthly</td></tr>
<tr><td>VOC</td><td>3.9 tons/year</td><td>5.5 lbs/mmscf</td></tr>
<tr><td>CO</td><td>28.2 tons/year</td><td>0.04 lb/mmBTU</td></tr>
<tr><td>Heat Input</td><td>3.5</td><td>1,410,300 mmBTU/year (total)</td><td></td><td>Recordkeeping</td><td>Monthly</td></tr>
<tr><td>Equipment Leaks</td><td>3.6</td><td>Leak Detection and Repair Program</td><td></td><td colspan="2">Inspection
See 40 CFR Part 63 Subpart CC, Condition 32</td></tr>
<tr><td>MACT</td><td>3.7</td><td>See Condition 33</td><td></td><td colspan="2">See 40 CFR Part 63, Subpart UUU, Condition 33</td></tr>
<tr><td rowspan="3">Opacity</td><td rowspan="3">3.8</td><td>Not to exceed 20%, except as provided for below</td><td></td><td rowspan="3">Fuel Type</td><td rowspan="3"></td></tr>
<tr><td>Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes</td><td></td></tr>
<tr><td>Not to exceed 20% - (State-Only)</td><td></td></tr>
</table>

Note that emissions from F004, Catalyst Regeneration (coke burn-off) are below the APEN de minimis level so an APEN for this activity is not required. However, this activity is subject to requirements in 40 CFR Part 63 Subpart UUU and as a result, this activity is included in the permit.

3.1 Emissions of air pollutants shall not exceed the limits listed above. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Emissions shall be calculated using the emission factors and the actual fuel usage in the following equations. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculation of emissions shall be based on the most recent fuel Btu and sulfur analyses. The permittee shall keep a compliance record on site for Division review. (Construction Permit 12AD032-1, revised per Section I, Condition 1.4 of this permit, to reflect revised PM/PM_{10} and VOC emission limits based on revised emission factors.)

Fuel Combustion: PM/PM_{10} Emissions (Tons/Year) = [EF (lbs/mmscf) x fuel usage (mmscf/year) x Btu correction]/2000 (lbs/ton)

Fuel Combustion: NOx/CO Emissions (Tons/Year) = [EF (lbs/mmBTU) x fuel usage (mmBTU/year)] /2000 (lbs/ton)

For APEN reporting and fee purposes, annual emissions from fuel combustion shall be calculated using: the emission factors listed above and the annual fuel usage in the equation listed above. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculation of annual emissions shall be based on the most recent fuel Btu and sulfur analyses.

3.2 These sources are subject to the particulate matter emission limits set forth in Conditions 20.1 and 20.2 of this permit.

3.3 Heaters #1, 2 and 3 (B003, B004, and B005) are subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 22.5 of this permit.

3.4 Sulfur dioxide emissions from these sources shall be included when evaluating compliance with the Colorado Regulation Nos. 1 and 6, Part B emission limits set forth in Conditions 22.1 and 22.2 of this permit.

3.5 Total heat input shall not exceed the limit listed in the table above. (Construction Permit 12AD032-4) Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Monthly and rolling twelve month records of the actual consumption rate shall be maintained by the applicant and made available to the Division for inspection upon request.

A flow device is used to monitor fuel use. Fuel use shall be recorded daily, and summed monthly. Fuel use shall be converted to Btu use using the most recent heat value analysis. In the event that the flow device becomes inoperable, fuel use data shall be obtained from the Refinery Yields data system (an internal material balance and accounting system). If, after review, the Yields system is determined by Suncor to not provide sufficient or accurate daily fuel use data, the maximum-fired duty for the fired source will be conservatively assumed.

Fuel Sampling

The refinery fuel gas used in these combustion sources shall be analyzed at least once per week for heat value. (Construction Permit 12AD032-4, revised to omit analysis of sulfur content, which is instead required under 40 CFR Subpart J, Condition 22.5 of this permit.)

Records of the daily and monthly fuel use, and fuel heating value analyses shall be maintained and made available for inspection upon request.

3.6 Equipment leak emissions associated with the Hydrotreater and Reformer (F005 and F007) are subject to the requirements of 40 CFR Part 63, Subpart CC, as set forth in Condition 32 of this permit.

3.7 This unit is subject to the requirements of 40 CFR Part 63, Subpart UUU as set forth in Condition 33 of this permit.

3.8 These sources are subject to the opacity limits set forth in Conditions19.1, 19.2, and 19.4 of this permit.

4. Polymerization Unit – P006; F008 – Reactor #1 (Catalyst Unloading); F029 – Reactor #1 (Catalyst Loading); F009 – Reactor #2 (Catalyst Unloading); F030 – Reactor #2 (Catalyst Loading)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	4.1		275 lbs/reactor blowdown Catalyst loading: 0.0024 lb/ton loaded	Recordkeeping Calculation	Annually
PM_{10}	4.1		275 lbs/reactor blowdown Catalyst loading: 0.0024 lb/ton loaded	Recordkeeping Calculation	Annually
Blowdowns	4.2			Recordkeeping	Monthly
Equipment Leaks	4.3	Leak Detection and Repair Program		Inspection See 40 CFR Part 63 Subpart CC, Condition 32	
Opacity	4.4	Not to exceed 20%, except as provided for below		Standard Operating Procedures Method 9	Semi-Annually
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			

4.1 For APEN reporting and fee purposes, annual emissions for P006 shall be calculated using the emission factors listed above and the actual number of blowdowns in the following equation. Annual emissions for catalyst unloading shall be calculated using the emission factors listed above and the actual amount of catalyst loaded in the equation listed below.(Colorado Regulation No. 3, Part A, Section II)

P006: Emissions (Tons/Year) = [EF (lbs/reactor blowdown) x number of blowdowns]/2000 (lbs/ton)

Catalyst Loading: Emissions (Tons/Year) = [EF (lb/ton loaded) x amount of catalyst loaded (tons)]/2000(lbs/ton)

4.2 Records of the number of reactor blowdowns shall be maintained by the applicant and made available to the Division for inspection upon request.

4.3 Equipment leak emissions associated with the Polymerization Unit (F010) are subject to the requirements of 40 CFR Part 63, Subpart CC, as set forth in Condition 32 of this permit.

4.4 These sources are subject to the opacity limits set forth in Conditions 19.1 and 19.2 of this permit.

5. Sulfur Recovery Plant – P009; P009 – Sulfur Recovery Unit; P008 – Amine Unit; P010 – Sour Water Stripper

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	5.1		7.6 lbs/mmscf	Recordkeeping Calculation	Monthly Annually
PM_{10}	5.1		7.6 lbs/mmscf	Recordkeeping Calculation	Monthly Annually
SO_2	5.1	344.0 tons/year	Per Appendix H	Recordkeeping Calculation	Monthly Annually
	5.11	Fuel gas shall not contain H_2S in excess of 0.10 gr/scf		Continuous Emission Monitor	Continuous per 60.13
	5.2	0.3 lb SO_2/bbl of oil processed **(State-Only)**	Per Appendix H	Recordkeeping Calculation	Daily Annually
		0.3 lb SO_2/bbl/day of oil processed			Daily Monthly
Claus Plant Operation	5.8	1.2% vol SO_2		CEM	Continuous per PSD permit QA plan
Nox	5.1	5.2 tons per year	100 lbs/mmscf	Recordkeeping Calculation	Monthly Annually
VOC			5.5 lbs/mmscf		
CO			84 lbs/mmscf		
H_2S	5.1	13.8 tons/year	Mass Balance		
	5.7	Amine Unit fuel gas: 0.080 grains/dscf, on a 12-month rolling average		See Condition 5.7.	
Gas Input	5.3	21,000 million BTU per year		Recordkeeping	Monthly
MACT Standard	5.4	See Condition 33 (effective April 11, 2005)			
Equipment Leaks	5.5	Leak Detection and Repair Program		Inspection See 40 CFR Part 63 Subpart CC, Condition 32	
Opacity	5.6	Not to exceed 20%, except as provided for below		Visual Inspection Method 9	Monthly If visible >6 minutes and quarterly
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PSD Monitoring Requirements	5.9	See Condition 5.9			
PSD Reporting Requirements	5.10	See Condition 5.10			

5.1 Emissions of air pollutants shall not exceed the limits listed above. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Emissions shall be calculated using the emission factors listed above and actual fuel usage in the following equation. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculation of emissions shall be based on the most recent Btu and sulfur analyses. The permittee shall keep a compliance record on site for Division review. (Construction Permit 12AD032-3)

Fuel consumed is monitored using flow devices and fuel heating value is determined by GC analysis.

For APEN reporting and fee purposes, annual emissions shall be calculated using the emission factors listed above and actual fuel usage in the following equation. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculation of annual emissions shall be based on the most recent Btu and sulfur analyses.

Emissions (Tons/Year) = [EF (lbs/mmscf) x fuel usage (mmscf/year) x Btu correction]/2000 (lbs/ton)

5.2 Sulfur dioxide emissions from these sources shall be included when evaluating compliance with the Colorado Regulations No. 1 and 6, Part B emission limits set forth in Conditions 22.1 and 22.2 of this permit.

5.3 Total quantity of gas input into the incinerator (tail gas and supplemental fuel gas) shall be limited to the equivalent of 21,000 million BTU per year.(Construction Permit 12AD032-3) Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Monthly and rolling twelve month records of the actual consumption rate shall be maintained by the applicant and made available to the Division for inspection upon request.

The following records shall be maintained on site, and made available to the Division for inspection upon request.

Actual quantity of tailgas incinerated

Analysis of tailgas entering the incinerator

Actual quantity of fuel gas, with its heat content, consumed

A flow device is used to monitor fuel use. Fuel use shall be recorded daily. In the event that the flow device becomes inoperable, fuel use data shall be obtained from the Refinery Yields data system (an internal material balance and accounting system). If, after review, the Yields system is determined by Suncor to not provide sufficient or accurate daily fuel use data, the maximum-fired duty for the fired source will be conservatively assumed.

Fuel Sampling

The refinery fuel gas shall be analyzed at least once per week for heat value.

Records of the daily and monthly fuel use, and fuel heating value analyses shall be maintained and made available for inspection upon request. Fuel use shall be converted to Btu use using the most recent heat value analysis.

5.4 This source is subject to 40 CFR Part 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, as set forth in Condition 33 of this permit.

5.5 Equipment leak emissions associated with the Amine Unit and Fuel Gas System (F013) are subject to the requirements of 40 CFR Part 63, Subpart CC, as set forth in Condition 32 of this permit.

5.6 These sources are subject to the opacity limits set forth in Conditions19.1, 19.2 and 19.4 of this permit.

5.7 The fuel gas from the Amine Unit shall contain not more than 0.080 grains of hydrogen sulfide per dry standard cubic foot, on a 12- month rolling average. (EPA PSD Permit, Condition 2(a), as modified under the provisions of Section I, Condition 1.4 to specify the averaging time). Compliance with this condition shall be monitored using the H_2S continuous monitoring system required by Condition 22.5.2 of this permit. A monthly average H_2S concentration shall be calculated by the end of the subsequent month using all hourly H_2S averages from the continuous monitoring system. The monthly H_2S concentration shall be adjusted to back out the dilution effect of the addition of any reformer gas, propane or natural gas to the refinery fuel gas for that month. The monthly adjusted H_2S concentration shall be used in a twelve month rolling average in order to monitor compliance with the annual limitation. Each month a new twelve month rolling average shall be calculated using the previous twelve months' data.

5.8 The Claus Plant shall operate when at least 0.80 long ton per day (LTD) of sulfur is available from specified regulated sources (i.e., crude vacuum unit, reformer unit and steam boiler) and specified nonregulated sources (i.e. two steam boilers, FCC preheater, and fuel oil tank heater) that feed into the Claus Plant. Compliance with this condition shall be monitored using data obtained from the monitoring required in Condition 5.9. (EPA PSD Permit, Condition 2(b), revised in accordance with Section I, Condition 1.4 of this permit)

If 0.80 LTD or more of sulfur is available from the regulated sources, then the routing of the nonregulated sources into the Claus unit is optional. The EPA and the Division shall be notified, in writing, when unregulated fuel gas is not treated by the Amine Unit and records shall be kept of the sulfur content and quantity of unregulated fuel gas burned. (PSD Permit, Condition (2)(c))

The owner and/or operator shall not discharge or cause the discharge of any gases into the atmosphere from the Claus Plant containing in excess of 1.20 percent by volume of sulfur dioxide at zero percent oxygen on a dry basis. Compliance with this emission limit shall be monitored using data from the Continuous Emission Monitor (CEM), required in Condition 5.9, or a stack test using EPA Method 6. Although the primary method of monitoring compliance is by this Condition, the Administrator may require the appropriate source test to validate the monitoring techniques. (EPA PSD Permit, Condition 2(d), revised in accordance with Section I, Condition 1.4 of this permit)

5.9 **PSD Permit Monitoring Requirements**

A continuous monitoring system for measuring SO_2 from the Claus plant shall be installed, calibrated, maintained, and operated by the owner or operator. A diluent monitor shall be operated along with the SO_2 monitor for the Claus plant, to correct measurements to zero-percent oxygen. These monitoring systems shall comply with the appropriate reporting requirements in 40 CFR Section 60.7(c). Periods of excess emissions are defined as any running twelve-hour period during which the average concentration of SO_2 in the gases discharged into the atmosphere exceed the emission limit in Condition 2(d) of the PSD permit. (EPA PSD Permit, Condition 4(a)) Whenever the CEM is not operating, emissions from the Claus plant will be determined in accordance with the procedures in Appendix H of this permit.

Recertification or other evaluation of the CEM's may be required by the EPA to demonstrate that the systems are operating within the allowable specifications. (EPA PSD Permit, Condition (5))

The permittee shall implement the quality control program for the continuous monitoring systems submitted and approved by the EPA. As specified in Condition (7) of the EPA PSD permit, the quality control program shall have written procedures for each of the following activities: installation of CEMS, calibration of CEMS, zero and calibration checks and adjustment for CEMS, data recording and reporting, program of corrective action for inoperative CEMS and annual evaluation of CEM systems. The EPA may require revisions to the QA plan as needed. (EPA PSD Permit, Condition (7)) A copy of the plan shall be maintained on site for Division inspection upon request.

This source is subject to the good operating practices set forth in Condition 36.5 of this permit. (EPA PSD Permit, Condition (8))

5.10 **PSD Permit Reporting Requirements**

The Applicant shall notify the EPA and the Division as soon as possible of excess emissions, as defined by emission limits in this permit, (not more than 48 hours after discovery) during periods of start-up, shut-down, equipment malfunction, or process upset. Not more than 10 days after discovery, all of the following shall be provided to the EPA and the Division in writing:

a. The identity of the stack or other emission point where excess emission occurred;

b. The magnitude of excess emissions expressed in terms of permit conditions;

c. Pertinent operating data during the time of upset;

d. The time duration of excess emissions;

e. The identity of the equipment or process causing the upset and the suspected reasons for the upset;

f. Steps and procedures taken during the upset period to minimize excess emissions;

g. Steps and procedures taken or anticipated to be taken to prevent reoccurrence of the upset conditions.

The Source will be considered to be in violation of the permit if the Division determines that the information submitted does not evidence a malfunction or upset condition caused by events beyond the control of the Applicant and the Source exceeded the emission or operational limits described in this permit. (PSD Permit, Condition 9)

5.11 Fuel gas from the refinery fuel gas system that is combusted as pilot gas or supplemental fuel in the tail gas incinerator is subject to the fuel gas requirements of 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 22.5 of this permit. Tail gas from the Claus unit is not considered fuel gas subject to the fuel gas requirements of 40 CFR Part 60, Subpart J. Emissions from the combustion of tail gas in the tail gas incinerator are not subject to the requirements of 40 CFR Part 60, Subpart J.

6. Utilities - B006 – Boiler 1; B007 – Boiler 2; B008 – Boiler 3; P011 – Cooling Tower

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring Method	Monitoring Interval
PM	6.1	4.6 tons/year	7.6 lbs/mmscf	Recordkeeping Calculation	Monthly Annually
	6.2	See Conditions 20.1 and 20.2		Fuel Type	
PM_{10}	6.1	4.6 tons/year	7.6 lbs/mmscf	Recordkeeping Calculation	Monthly Annually
SO_2	6.1	18.0 tons/year	Per Appendix H		
	6.3	Fuel gas shall not contain H_2S in excess of 0.10 gr/scf (B006, B007, B008)		Continuous Emission Monitor	Continuous per 60.13
	6.4	0.3 lb SO_2/bbl of oil processed (**State-Only**)	Per Appendix H	Recordkeeping Calculation	Daily Annually
		0.3 lb SO_2/bbl/day of oil processed			Daily Monthly
NOx	6.1	52.2 tons/year	Boiler 1: 50 lbs/mmscf Boiler 2 & 3: 100 lbs/mmscf	Recordkeeping Calculation	Monthly Annually
VOC		7.3 tons/year	2.5 lbs/mmscf		
CO		59.7 tons/year	84 lbs/mmscf		
Heat Input	6.5	1,205,000 mmBTU/year (total)		Recordkeeping	Monthly
NSPS (B006)	6.6			Fuel Use Recordkeeping	Daily
Equipment Leaks	6.7	Inspection and Repair		Inspection See 40 CFR Part 63 Subpart CC, Condition 32	
Opacity	6.8	Not to exceed 20%, except as provided for below		Boilers: Fuel Type P011: Good Engineering Practices	N/A
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			

6.1 Emissions of air pollutants shall not exceed the limits listed above. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. The permit holder shall calculate monthly and rolling twelve month emissions using the emission factors listed above and actual fuel usage in the following equation. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculation of emissions shall be based on the most recent Btu and sulfur analyses. The permittee shall keep a compliance record on site for Division review. (Construction Permit 87AD184, revised according to Section I, Condition 1.4 of this permit, to reflect revised emission factors)

Emissions (Tons/Year) = [EF (lbs/mmscf) x fuel usage (mmscf/year) x Btu correction]/2000 (lbs/ton)

For APEN reporting and fee purposes, annual emissions shall be calculated using the emission factors listed above and actual fuel usage in the following equation. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculation of annual emissions shall be based on the most recent Btu and sulfur analysis.

Emissions (Tons/Year) = [EF (lbs/mmscf) x fuel usage (mmscf/year) x Btu correction]/2000 (lbs/ton)

6.2 These sources are subject to the particulate matter emission limits set forth in Conditions 20.1 and 20.2 of this permit.

6.3 B006, B007, and B008 are subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 22.5 of this permit.

6.4 Sulfur dioxide emissions from these sources shall be included when evaluating compliance with the Colorado Regulations No. 1 and 6, Part B emission limits set forth in Conditions 22.1 and 22.2 of this permit.

6.5 Total refinery fuel gas consumed from combustion in the boiler facility shall not exceed the heat equivalent of 1,205,000 mmBTU per year. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Monthly and rolling twelve month total records of the actual consumption rate shall be maintained by the applicant and made available to the Division for inspection upon request. (Construction Permit 87AD184)

A flow device is used to monitor fuel use. Fuel use shall be recorded daily. In the event that the flow device becomes inoperable, fuel use data shall be obtained from the Refinery Yields data system (an internal material balance and accounting system). If, after review, the Yields system is determined by Suncor to not provide sufficient or accurate daily fuel use data, the maximum-fired duty for the fired source will be conservatively assumed.

Fuel Sampling

The refinery fuel gas shall be analyzed at least once per week for sulfur content and heat value.

Records of the daily and monthly fuel use, and fuel heating value analyses shall be maintained and made available for inspection upon request. (Construction Permit 87AD184) Fuel use shall be converted to Btu use using the most recent heat value analysis.

6.6 B006 – Boiler #1 is subject to the provisions of 40 CFR Part 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, as adopted by reference in Colorado Regulation No. 6, Part A, as follows.

The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. (60.48c(g))

In addition, this source is subject to 40 CFR Part 60, Subpart A provisions set forth in Condition 36 of this permit.

6.7 Equipment leak emissions associated with the Fuel Gas System (F014) are subject to the requirements of 40 CFR Part 63, Subpart CC, as set forth in Condition 32 of this permit.

6.8 These sources are subject to the opacity limits set forth in Conditions19.1, 19.2, and 19.4 of this permit.

7. Crude Unloading/Gasoline Tank Truck Loading; F015 – South Crude Unloading; F016 – North Crude Unloading; F024 – Truck Loading Dock

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
SO_2	7.2	Fuel gas shall not contain H_2S in excess of 0.10 gr/scf		Drager test	Semiannually
	7.3	0.3 lb SO_2/bbl of oil processed (**State-Only**)	Per Appendix H	Recordkeeping Calculation	Daily Annually
		0.3 lb SO_2/bbl/day of oil processed			Daily Monthly
NOx	7.1	Flare: 3.3 tons/year	0.068 lb/mmBtu	Recordkeeping Calculation	Monthly Annually
VOC		Truck Loading: vapor collection & processing system: 24.1 tons/year fugitive emissions from equipment leaks: 0.6 tons/year Crude Oil Unloading: 3.9 tons/year	Truck Loading: vapor collection & processing system: 10 mg/liter loaded fugitive emissions from equipment leaks: See Condition 7.1. Crude Loading: AP-42, Section 5.2		

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Truck Racks RACT	7.4	Storage and Transfer of Petroleum Liquid		See Colorado Regulation No.7, VI.C.2, Condition 25.3 and XV, Condition 28	
		Petroleum Processing and Refining		See Colorado Regulation No.7, VIII, Condition 27	
Crude Racks RACT	7.5	Storage and Transfer of Petroleum Liquid		Inspection & Repair	See Regulation No.7, VIII.C
CO	7.1	Flare: 17.7 tons/year	.37 lb/mmBtu	Recordkeeping Calculation	Monthly Daily
Throughput	7.6	Truck Loading Docks: 578,160,000 gallons petroleum products/year Crude Oil: 378,000,000 gallons (9,000,000 barrels)/year		Recordkeeping	Monthly
MACT	7.7	See 40 CFR Part 63 Subpart CC		See 40 CFR Part 63 Subpart CC, Condition 32	
Opacity	7.8	Flare: Not to exceed 30% for a period or periods aggregating more than six minutes in any sixty consecutive minutes		Visible Inspection	Monthly (may be reduced)
Flare Operation	7.9	See Condition 37		Method 22	If visible emissions

7.1 Emissions of air pollutants shall not exceed the limits listed above. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Emissions shall be calculated using the emission factors and methods listed above and keep a compliance record (emission calculations) on site for Division review. (Construction Permits 11AD251 and 93AD592, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to revised flare and truck loading dock emission limitations as indicated on the APEN submitted June 18, 2008)

For APEN reporting and fee purposes, annual emissions shall be calculated using the emission factors listed above for the truck loading vapor collection and processing system (includes the flare) and crude loading and the emission factors listed in the table below for truck loading fugitive emissions from equipment leaks. Calculation of annual emissions shall be based on the most recent Btu and sulfur analysis and actual throughput.

Component Type	Emission Factor (lb/hr-component)	Emission Factor Source
Valves	5.21 x 10^{-4}	EPA's Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Table 2-10, Screening Value 500 ppm.
Other	1.17 x 10^{-4}	
Connector	3.25 x 10^{-4}	
Flange	8.02 x 10^{-4}	

7.2 The Truck Loading Dock Flare is subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 22.5 of this permit. (Consent Decree, No. 99-1759, filed September 8, 1999)

H_2S content in vapor during product loading: (truck docks) H_2S colorimetric tube testing is done by EPA-approved alternative monitoring method. Colorimetric tube measurement shall be taken during one loading event each six-month period. If any colorimetric tube H_2S measurement exceeds 40 ppm, the permittee shall report the event to the Division. The H_2S colorimetric tube testing may be discontinued provided that a demonstration that the fuel gas stream is inherently low in sulfur is submitted in accordance with the requirements in 40 CFR Part 60 Subpart J § 60.105(b) and the previously approved alternative monitoring method is rescinded by EPA.

7.3 Sulfur dioxide emissions (if any) from these sources shall be included when evaluating compliance with the Colorado Regulations No. 1 and 6, Part B emission limits set forth in Conditions 22.1 and 22.2 of this permit.

7.4 The truck loading docks are subject to the Colorado Regulation No. 7, VI.C.2, and VIII.B and C provisions set forth in Conditions 25.3, and 27 of this permit. In lieu of the testing, monitoring, and recordkeeping requirements of Regulation No. 7, VIII.B.6, compliance with the provisions of 40 CFR Part 60, Subpart A, 60.18 shall be considered compliance with the provisions of VIII.B.6. The tank truck loading docks are subject to the provisions of Colorado Regulation No. 7, Section XV, set forth in Condition 28 of this permit, as required by VI.C.2.b(ix).

A thermocouple is used to monitor proper combustion of vapors at the flare, based on continuous temperature data collected at the combustion flame envelope. Proper combustion occurs at a temperature of 500 °F or higher averaged on a 12 hour rolling basis. The average temperature will be calculated utilizing only the cumulative periods of time that loading is occurring and flow is directed to the flare. When a value is calculated on a 12 hour rolling average that is below 500 °F, the occurrence will be noted and reported to the Division in the Refinery MACT periodic report for that period, and in the semi-annual operating permit report. The computer maintains the combustion system within the temperature range that ensures near complete combustion. If the temperature is outside the acceptable combustion range, the computer locks out all product loading. All instances when product loading is locked out shall be investigated. When the investigation identifies the temperature in the combustor was outside the acceptable range, the truck dock loading records shall be reviewed to determine if loading occurred during that time. Records when loading outside of the acceptable range shall be kept for inspection upon request. Such events shall be reported to the Division in the semi-annual report. The acceptable temperature range shall be based on the most recent Division approved performance test results.

7.5 The Crude Oil Unloading Racks are subject to the Colorado Regulation No. 7,VI.A provisions set forth in Condition 25.1 of this permit.

7.6 Total process rate in terms of throughput (transfer rate) of petroleum products transferred in the truck loading docks shall not exceed 578,160,000 gallons per year. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Monthly and rolling twelve month records of the actual consumption rate shall be maintained by the applicant and made available to the Division for inspection upon request.(Construction Permit 11AD251)

Total unloading of crude oil shall not exceed 378,000,000 gallons (9,000,000 barrels) per year. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Monthly and rolling twelve month records of the actual consumption rate shall be maintained by the applicant and made available to the Division for inspection upon request. (Construction Permit 93AD592)

7.7 The Truck Loading Docks (F024) are subject to the requirements of 40 CFR Part 63, Subpart CC, as set forth in Condition 32 of this permit.

7.8 The flare is subject to the opacity limit set forth in Condition 19.3 of this permit.

7.9 The flare is subject to the provisions of 40 CFR Part 60, 60.18, as set forth in Condition 37 of this permit.

8. Refinery Flare - Process Relief Valves Vented to Refinery Flare: P001, P003, P005, P006, P007, P008, P013

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
SO_2	8.1	172.0 tons/year	Per Appendix H		
	8.2	0.3 lb SO_2/bbl of oil processed (**State-Only**)	Per Appendix H	Recordkeeping Calculation	Daily Annually
		0.3 lb SO_2/bbl/day of oil processed			Daily Monthly
	8.3	Root Cause Failure Analyses Good Operating Practices		Root Cause Failure Analysis	Each Event
	8.4	**After 12/31/07:** See Compliance Plan Required by Condition 22.5.4		See Condition 22.5.4	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
NO_X	8.1	4.6 tons/year	0.068 lb/mmBtu (pilot gas) 18.90 lbsMbbl crude processed (Refining: AP-42, Table 5.1-1) (flared gas for APEN and fees)	Recordkeeping Calculation	Monthly Annually
VOC		3.8 tons/year	0.056 lb/mmBtu (pilot gas) 0.80 lb/Mbbl crude processed (Refining: AP-42, Table 5.1-1) (flared gas for APEN and fees)		
RACT	8.5	See Colorado Regulation No. 7,VIII.B.6		See Colorado Regulation No. 7,VIII.B.6, Condition 27.6	
NSPS	8.6	See 40 CFR Part 60, Subpart GGG		See 40 CFR Part 60 Subpart GGG, Condition 32	
CO	8.1	24.7 tons/year	0.37 lb/mmBtu (pilot gas) 4.30 lbs/Mbbl crude processed (Refining: AP-42, Table 5.1-1) (flared gas for APEN and fees)	Recordkeeping Calculation	Monthly Annually
Heat Input	8.8			Recordkeeping	Monthly
Opacity	8.9	Not to exceed 30% for a period or periods aggregating more than six minutes in any sixty consecutive minutes		Visible Inspection Method 22	Monthly (may be reduced) If visible emissions
Flare Operation	8.10	See Condition 37			

8.1 Emissions of air pollutants shall not exceed the limits listed above. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. The permit holder shall calculate monthly and rolling twelve month emissions using the emission factors listed above and actual pilot fuel usage in the following equation. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculation of emissions shall be based on the most recent Btu and sulfur analyses. The permittee shall keep a compliance record (emission calculations) on site for Division review. (Construction Permit 88AD134)

Emissions (Tons/Year) = [EF (lbs/mmBtu) x fuel usage (mmBtu/year) x Btu correction]/2000 (lbs/ton)

For APEN reporting and fee purposes, annual emissions from pilot gas combustion shall be calculated using the emission factors listed above and actual fuel usage in the following equation. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculation of annual emissions shall be based on the most recent Btu and sulfur analyses.

Emissions (Tons/Year) = [EF (lbs/mmBtu) x fuel usage (mmBtu/year) x Btu correction]/2000 (lbs/ton)

In addition, for APEN reporting and fee purposes, annual emissions from flaring events shall be calculated using the emission factors listed above and actual amount of crude processed in the following equation. SO_2 emissions shall be estimated as set forth in Appendix H of this permit.

Emissions (Tons/Year) = [EF(lbs/mmbbl crude processed) x crude processed (mmbbl/year)]/2000 (lbs/ton)

8.2 Sulfur dioxide emissions from this source shall be included when evaluating compliance with the Colorado Regulations No. 1 and 6, Part B emission limits set forth in Conditions 22.1 and 22.2 of this permit.

8.3 Flare Operation, Monitoring, and Reporting

8.3.1 Good Air Pollution Control Practices On and after November 23, 2005, Suncor shall at all times and to the extent practicable, including during periods of Startup, Shutdown, and/or Malfunction, implement good air pollution practices for minimizing emissions consistent with 40 CFR § 60.11(d). (Consent Decree, No. SA-05-CA-0569, entered November 23, 2005, Paragraph 234)

8.3.2 Root Cause Failure Analysis Suncor shall conduct a Root Cause Failure Analysis for flaring events as required by and in accordance with the Consent Decree (No. SA-05-CA-0569) between Valero, the State of Colorado and the U.S. EPA entered on November 23, 2005. (Consent Decree, No. SA-05-CA-0569, entered November 23, 2005, Paragraph 242)

8.4 In accordance with the “Compliance Plan for Flaring Devices” required by the “Consent Decree” and Condition 22.5.4, on or before December 31, 2007, this source is subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 22.5 of this permit. [Note: The Consent Decree in Paragraph 238(a) allows for a compliance demonstration by December 31, 2007 or by December 31, 2008 if a flare gas recovery system is selected.] (Consent Decree, No. SA-05-CA-0569, entered November 23, 2005, Paragraphs 237 and 238)

8.5 This source is subject to the provisions of Colorado Regulation No. 7, VIII.B.6 as set forth in Condition 27.6 of this permit. In lieu of the testing, monitoring, and recordkeeping requirements of Regulation No. 7, VIII.B.6, compliance with the provisions of 40 CFR Part 60, Subpart A, 60.18 shall be considered compliance with the provisions of VIII.B.6.

8.6 This source is subject to 40 CFR Part 60, Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, as set forth in Condition 30 of this permit.

8.7 Leaks from pump seals shall be vented to the flare. (Construction Permit 88AD134)

8.8 Records of the actual heat input rate shall be maintained by the permittee and made available to the Division for inspection upon request.

Pilot fuel is monitored using flow devices and the fuel heating value is determined from GC analysis.

Fuel Sampling

The refinery fuel gas shall be analyzed at least once per week for heat value.

Records of the daily and monthly fuel use, and fuel heating value analyses shall be maintained and made available for inspection upon request. Fuel use shall be converted to Btu use using the most recent heat value analysis.

8.9 This source is subject to the opacity limit set forth in Condition 19.3 of this permit.

8.10 This source is subject to the provisions of 40 CFR Part 60, 60.18, as set forth in Condition 37 of this permit. Flare pilot flame monitored using a thermocouple, infrared sensor, video monitor, or equivalent device.

9. Liquefied Petroleum Gas (LPG) Storage Truck and Rail Facility - F019 – Railcar Dock; F020 – Truck Dock; Grandfathered Pressure Tanks: T050, T051, T060, T061, T063, T064; Permitted Pressure Tanks: T066, T067, T068, T069

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	9.1	Flare: 1.0 ton/year	1.14×10^{-6} lb/gallon	Recordkeeping Calculation	Monthly Annually
PM_{10}		Flare: 1.0 ton/year			
SO_2		1.0 ton/year	Per Appendix H		
	9.2	Fuel gas shall not contain H_2S in excess of 0.10 gr/scf		Continuous Emission Monitor	Continuous per 60.13
	9.3	0.3 lb SO_2/bbl of oil processed (**State-Only**)	Per Appendix H	Recordkeeping Calculation	Daily Annually
		0.3 lb SO_2/bbl/day of oil processed			Daily Monthly

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
NOx	9.1	13.8 tons/year	0.068 lb/mmBtu	Recordkeeping Calculation	Monthly Annually
VOC		28.3 tons/year	Flare: 0.14 lb/mmBtu Loading: AP-42, Section 5.2		
Storage Tank RACT	9.4	Storage of Highly Volatile Organic Compounds		Verify pressures and set points	Annually
RACT	9.5	See Condition 9.5		See Condition 9.5	
MACT	9.6	See 40 CFR Part 63 Subpart CC		See 40 CFR Part 63 Subpart CC, Condition 32	
CO	9.1	74.9 tons/year	0.37 lb/mmBtu	Recordkeeping Calculation	Monthly Annually
Throughput	9.7	350,000,000 gallons LPG/year 88,000,000 gallons other petroleum products/year		Recordkeeping	Monthly
Opacity	9.8	Not to exceed 30% for a period or periods aggregating more than six minutes in any sixty consecutive minutes		Visual Inspection Method 22	Monthly (may be reduced) If visible emissions
Flare Operation	9.9	See Condition 37			
Loading Restriction	9.10	Petroleum products in railcars only			

9.1 Emissions of air pollutants shall not exceed the limits listed above. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. The permit holder shall calculate monthly and twelve month rolling emissions using the emission factors and methods listed above and keep a compliance record on site for Division review. Calculation of emissions shall based on the most recent Btu and sulfur analyses. (Construction Permit 89AD031)

For APEN reporting and fee purposes, annual emissions shall be calculated using the emission factors listed above. Calculation of annual emissions shall be based on the most recent Btu and sulfur analysis.

9.2 The rail car dock flare is subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 22.5 of this permit.

H_2S colorimetric tube testing done by EPA-approved alternative monitoring method. Colorimetric tube measurement taken during one loading event during each six-month period. If any colorimetric tube H_2S measurement exceeds 40 ppm, the permittee shall report the event to the Division. The H_2S colorimetric tube testing may be discontinued provided that a demonstration that the fuel gas stream is inherently low in sulfur is submitted in accordance with the requirements in 40 CFR Part 60 Subpart J § 60.105(b) and the previously approved alternative monitoring method is rescinded by EPA.

9.3 Sulfur dioxide emissions from the rail dock flare shall be included when evaluating compliance with the Colorado Regulations No. 1 and 6, Part B emission limits set forth in Conditions 22.1 and 22.2 of this permit.

9.4 The LPG storage tanks are subject to the provisions of Colorado Regulation No. 7, Section IV, as set forth in Condition 24 of this permit.

9.5 These sources are subject to Colorado Regulation No. 7, VI.C.2, VI.C.4.a, and VIII.B.6 as set forth in Conditions 25.3, 25.4, and 27.6 of this permit. In lieu of the testing, monitoring, and recordkeeping requirements of Regulation No. 7, VIII.B.6, compliance with the provisions of 40 CFR Part 60, Subpart A, 60.18 shall be considered compliance with the provisions of VIII.B.6. These sources are subject to the provisions of Colorado Regulation No. 7, Section XV, set forth in Condition 28 of this permit, as required by VI.C.2.b(ix).

9.6 The Docks are subject to the requirements of 40 CFR Part 63, Subpart CC, as set forth in Condition 32 of this permit.

9.7 Loading of liquefied petroleum gas (LPG) shall not exceed 350,000,000 gallons per year. Loading of other petroleum products (including gasolines/blends) shall not exceed 88,000,000 gallons per year. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Monthly and rolling twelve month records of the actual consumption rate shall be maintained by the applicant and made available to the Division for inspection upon request. (Construction Permit 89AD031)

Number of cars loaded shall be recorded and kept on file. Emissions calculated based on number of cars loaded. Throughputs calculated based on number of cars loaded. Control device efficiency is based on a well designed and operated flare.

9.8 The flare is subject to the opacity limit of Colorado Regulation No. 1, Section II.A.3, as set forth in Condition 19.3 of this permit.

9.9 The flare is subject to the provisions of 40 CFR Part 60, 60.18, as set forth in Condition 37 of this permit.

9.10 At the LPG storage, truck, and rail facilities, petroleum products shall be loaded into railcars only. If loading of petroleum products other than LPGs into tanker trucks is contemplated, an application for modification to this permit shall be made. (Construction Permit 89AD031, revised in accordance with Section I, Condition 1.4 of this permit)

10. Wastewater Treatment System (WWTS) - F021 – API Separators – Upper API; F022 – API Separators – Middle API; F023 – API Separators – Lower API; F012 – Gas Plant Sewers; F025 – Sour Water Stripper Sewers

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	10.1	F022: 4.80 tons/year	WATER Model	Recordkeeping Calculation	Monthly Annually
Wastewater/Oil Separators RACT	10.3	Wastewater/Oil Separators		Inspection	Daily
NSPS	10.2	Drain and oil-water separator requirements		Inspection and Repair	Weekly Semi-annually
MACT	10.4	See 40 CFR Part 63 Subpart CC		See 40 CFR Part 63 Subpart CC, Condition 32	
Benzene	10.5	Sampling & Recordkeeping		Sampling & Recordkeeping	See 40 CFR Part 61 Subpart FF
Throughput	10.6	F022: 182,500,000 gallons water treated/year		Recordkeeping	Monthly

10.1 Emissions of air pollutants from the Middle API Separator (F022) shall not exceed the limit listed above. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Emissions shall be calculated using the method listed above and keep a compliance record on site for Division review. (Construction Permit 95AD1073-5)

For APEN reporting and fee purposes, annual emissions for all sources shall be calculated using the emission factors listed above. Calculation of annual emissions shall be based on the most recent water analyses.

10.2 Gas Plant Sewers (F012), Upper API Separator (F021), and Sour Water Stripper Sewers (F025), are subject to 40 CFR Part 60, Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems, as set forth in Condition 31 of this permit.

10.3 The Upper API Separator (F021), Middle API Separator (F022), and Lower API Separator (F023) are subject to Colorado Regulation No. 7, VIII.A.2 as set forth in Condition 27.1 of this permit.

10.4 This source is subject to the requirements of 40 CFR Part 63, Subpart CC, as set forth in Conditions 32.12, 32.13, and 32.14 of this permit.

10.5 Facility waste at this source is subject to the sampling and reporting requirements of 40 CFR Part 61, Subpart FF as set forth in 61.355(a)(4).

10.6 Water treated in F022 shall not exceed 182,500,000 gallons per year. Compliance with the annual limit shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Records of the actual consumption rate shall be maintained by the applicant and made available to the Division for inspection upon request. (Construction Permit 95AD1073-5)

The following records shall be maintained on site and made available to the Division upon request:

Actual quantities of water treated.

The quantity of water through the middle API separator will be determined on a 12-month rolling total basis. Emissions will be prepared and records maintained.

11. Black Oil Heater – B009

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	11.1		0.005 lb/mmBtu	Recordkeeping Calculation	Monthly Annually
	11.2	See Conditions 20.1 and 20.2		Fuel Type	
PM_{10}	11.1		0.005 lb/mmBtu	Recordkeeping Calculation	Monthly Annually
SO_2		2.1 tons/year	Per Appendix H		
	11.3	Fuel gas shall not contain H_2S i excess of 0.10 gr/scf		Continuous Emission Monitor	Continuous per 60.13
	11.4	0.3 lb SO_2/bbl of oil processed (**State-Only**)	Per Appendix H	Recordkeeping Calculation	Daily Annually
		0.3 lb SO_2/bbl/day of oil processed			Daily Monthly
NOx	11.1	3.8 tons/year	0.11 lb/mmBtu	Recordkeeping Calculation	Monthly Annually
VOC			0.005 lb/mmBtu		
CO		1.1 tons/year	0.03 lb/mmBtu		
Heat Input	11.5	69,984,000,000 BTU per year		Recordkeeping	Monthly
Opacity	11.6	Not to exceed 20%, except as provided for below		Fuel Type	
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			

11.1 Emissions of air pollutants shall not exceed the limits listed above. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. The permit holder shall calculate monthly and rolling twelve month emissions using the emission factors listed above and the actual fuel usage in the following equation. SO_2 emissions shall be estimated as set forth in the most recently approved SO_2 Plan. Calculation of emissions shall be based on the most recent Btu and sulfur analyses. The permittee shall keep a compliance record on site for Division review. (Construction Permit 95AD1073-4)

For APEN reporting and fee purposes, annual emissions shall be calculated using the emission factors listed above and the actual fuel usage in the following equation. SO_2 emissions shall be estimated as set forth in Appendix H of this permit. Calculation of annual emissions shall be based on the most recent Btu and sulfur analysis.

Emissions (Tons/Year) = [EF (lbs/mmBTU) x fuel usage (mmBTU/year)]/2000 (lbs/ton)

11.2 This source is subject to the particulate matter emission limits set forth in Conditions 20.1 and 20.2 of this permit.

11.3 This source is subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 22.5 of this permit.

11.4 Sulfur dioxide emissions from this source shall be included when evaluating compliance with the Colorado Regulations No. 1 and 6, Part B emission limits set forth in Conditions 22.1 and 22.2 of this permit.

11.5 This source shall be limited to a heat input of 69,984,000 BTU per year. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Monthly and rolling twelve month records of the actual consumption rate shall be maintained by the applicant and made available to the Division for inspection upon request. (Construction Permit 95AD1073-4)

A flow device is used to monitor fuel use. Fuel use shall be recorded daily. In the event that the flow device becomes inoperable, fuel use data shall be obtained from the Refinery Yields data system (an internal material balance and accounting system). If, after review, the Yields system is determined by Suncor to not provide sufficient or accurate daily fuel use data, the maximum-fired duty for the fired source will be conservatively assumed.

Fuel Sampling

The refinery fuel gas shall be analyzed at least once per week for heat value.

Records of the daily and monthly fuel use, and fuel heating value analyses shall be maintained and made available for inspection upon request. Fuel use shall be converted to Btu use using the most recent heat value analysis.

11.6 These sources are subject to the opacity limits set forth in Conditions 19.1, 19.2, and 19.4 of this permit.

12. Group B Tanks – Grandfathered, Internal Floating Roof Tanks – T010, T011, T027, T030, T040, T041

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	12.1		TANKS or AP-42	Recordkeeping Calculation	Annually
MACT	12.2	See 40 CFR Part 63 Subpart CC		See 40 CFR Part 63 Subpart CC, Condition 32	
RACT	12.3	See Condition 12.3		See Condition 12.3	
Throughput	12.4			Recordkeeping	Monthly

12.1 For APEN reporting and fee purposes, annual emissions shall be calculated using the most recent valid version of the EPA's TANKS program or EPA AP-42 emission factors and actual throughput. Records of emission calculations shall be maintained and made available for inspection upon request. (Colorado Regulation No. 3, Part A, Section II)

12.2 These sources are subject to 40 CFR Part 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as set forth in Condition 32 of this permit.

12.3 These tanks are subject to Colorado Regulation No. 7, III.A, VI.A.1, VI.B.2.a, and VI.B.2.b as set forth in Conditions 23.1, 25.1, 25.2.1, and 25.2.2 of this permit.

12.4 Records of the monthly and annual throughputs for each tank, and other data necessary for calculating emissions, shall be maintained on site and made available to the Division upon request.

13. Group C Tanks – Grandfathered, Fixed Roof Storing Exempted Materials – T008, T009, T042, T043, T045, T048, T049, T057

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	13.1		TANKS or AP-42	Recordkeeping Calculation	Annually
MACT	13.2	See 40 CFR Part 63 Subpart CC		See 40 CFR Part 63 Subpart CC, Condition 32	
RACT	13.3	Minimize VOC emissions		Inspection	Semi-Annually
Throughput	13.4			Recordkeeping	Monthly

13.1 For APEN reporting and fee purposes, annual emissions shall be calculated using the most recent valid version of the EPA's TANKS program or EPA AP-42 emission factors and actual throughput. Records of emission calculations shall be maintained and made available for inspection upon request. (Colorado Regulation No. 3, Part A, Section II)

13.2 These sources are subject to 40 CFR Part 63, Subpart CC, as set forth in Condition 32 of this permit.

13.3 These sources are subject to Colorado Regulation No. 7, III.A as set forth in Condition 23.1 of this permit.

13.4 Records of the monthly and annual throughputs for each tank, and other data necessary for calculating emissions, shall be maintained on site and made available to the Division upon request.

14. Group D Tanks – Grandfathered, Fixed Roof Vapor Pressure <0.65 psia - T004, T005, T031, T039, T055, T056

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	14.1		TANKS or AP-42	Recordkeeping Calculation	Annually
MACT	14.2	See 40 CFR Part 63 Subpart CC		See 40 CFR Part 63 Subpart CC, Condition 32	
RACT	14.3 – 14.4	Minimize Leaks and External Coating			
Throughput	14.5			Recordkeeping	Monthly

14.1 For APEN reporting and fee purposes, annual emissions shall be calculated using the most recent valid version of the EPA's TANKS program or EPA AP-42 emission factors and actual throughput. Records of emission calculations shall be maintained and made available for inspection upon request. (Colorado Regulation No. 3, Part A, Section II)

14.2 These sources are subject to 40 CFR Part 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as set forth in Condition 32 of this permit.

14.3 These sources are subject to Colorado Regulation No. 7, III.A as set forth in Condition 23.1 of this permit.

14.4 These sources are subject to Colorado Regulation No. 7, VI.B.2.b as set forth in Condition 25.2.2 of this permit.

14.5 Records of the monthly and annual throughputs for each tank, and other data necessary for calculating emissions, shall be maintained on site and made available to the Division upon request.

15. Group E Tanks – Tanks with Unique Requirements - T006, T012, T020, T024, T026, T038, T046, T047, T053, T062, T079

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	15.1	T006: 16.7 tons/year T020: 0.96 tons/year T024: 1.9 ton/year T026: 4.58 tons/year T046: 0.56 ton/year T047: 4.4 tons/year T053: 3.77 tons/year T062: 3.76 tons/year T079: 2.1 tons/year	TANKS or AP-42	Recordkeeping Calculation	Monthly Annually
RACT	15.2 – 15.7	See Conditions 15.2– 15.7		See Conditions15.2– 15.7	
NSPS	15.8	NSPS Subpart Kb		See 40 CFR Part 60 Subpart Kb, Condition 29	
MACT	15.9	See 40 CFR Part 63 Subpart CC		See 40 CFR Part 63 Subpart CC, Condition 32	
Throughput	15.10	T006: 689,850,000 gallons petroleum products/year T020: 400,000 barrels off specification products (slop oil) or heavier petroleum product/year T024: 119,000 barrels gasoline or lower vapor pressure petroleum liquids/year T026: 674,520,000 gallons crude oil or heavier petroleum product/year T046: 158,000 barrels/year T047: 69,930,000 gallons gasoline (RVP 10) or heavier petroleum product/year T053: 168,630,000 gallons petroleum products/year T062: 45,360,000 gallons light straight gasoline/year; 153,300,000 gallons reformate/year; 153,300,000 gallons naphtha/year; 39,850,000 gallons FCC Gasolines/year T079: 12,000,000 barrels gas oil or heavier petroleum products/year		Recordkeeping	Monthly

15.1 Emissions of air pollutants shall not exceed the limits listed above. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Compliance with the emission limits shall be assumed whenever the throughput limits listed in Condition 15.10 are met. (Construction Permits 95AD1073-1, 93AD306, 99AD0941, 00AD0183 (as modified under the provisions of Section I, Condition 1.4 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to revise emissions as indicated on the APEN submitted June 4, 2007), 88AD289-2, 95AD1073-3, and 93AD763. For T079, as provided for under the provisions of Section I, Condition 1.4 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to include emissions as requested on the APEN submitted September 10, 2007)

For APEN reporting and fee purposes, annual emissions shall be calculated using the most recent valid version of the EPA's TANKS program or EPA AP-42 emission factors and actual throughput. Records of emission calculations shall be maintained and made available for inspection upon request.

15.2 These tanks are subject to Colorado Regulation No. 7, Section III.A, as set forth in Condition 23.1 of this permit.

15.3 T006, T020, T024, T026, T038, T046, T047, T053, T062 and T079 are subject to Colorado Regulation No. 7, Section VI.A.1, as set forth in Condition 25.1 of this permit.

15.4 T006, T020, T024, T053, and T062 are subject to Colorado Regulation No. 7, VI.B.2.a as set forth in Condition 25.2.1 of this permit.

15.5 These tanks are subject to Colorado Regulation No. 7, Section VI.B.2.b, as set forth in Condition 25.2.2 of this permit.

15.6 T026, T038, and T047 are subject to Colorado Regulation No. 7, VI.B.2.c as set forth in Condition 25.2.3 of this permit. T012 is exempt from the requirements, except for the recordkeeping requirements of VI.B.2.c(ii)(C).

15.7 T006, T026, and T038 are subject to Colorado Regulation No. 7, Sections VII.B and VII.C as set forth in Condition 26 of this permit.

15.8 T006, T020, T026, T046, T047, T053, and T062 are subject to 40 CFR Part 60, Subpart Kb, as set forth in Condition 29 of this permit.

15.9 These sources are subject to 40 CFR Part 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as set forth in Condition 32 of this permit.

15.10 This source shall be limited to throughputs as follows. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. Monthly and rolling twelve month records of the actual throughput rate shall be maintained by the applicant and made available to the Division for inspection upon request.

T006: Storage/transfer of petroleum products shall not exceed 689,850,000 gallons per year. (Construction Permit 95AD1073-1)

T020: Processing of off specification products (slop oil) or heavier petroleum product shall not exceed 400,000 barrels per year. (Construction Permit 93AD306, revised in accordance with Section I, Condition 1.4 of this permit)

T024: Total throughput of gasoline or lower vapor pressure petroleum liquids shall not exceed 119,000 barrels per year. (Construction Permit 00AD0183, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to revise throughput limits as indicated on the APEN submitted June 4, 2007)

T026: Storage of Crude Oil or heavier petroleum product shall not exceed 674,520,000 gallons per year. (Construction Permit 99AD0941)

T047: Storage and handling of gasoline (RVP 10) or heavier petroleum product shall not exceed 69,930,000 gallons per year. (Construction Permit 88AD289-2)

T053: Storage/transfer of petroleum products shall not exceed 168,630,000 gallons per year. (Construction Permit 95AD1073-3)

T062: Light Straight Gasoline: 45,360,000 gallons per year; Reformate: 153,300,000 gallons/year; Naphtha: 153,300,000 gallons per year; FCC Gasolines: 39,850,000 gallons per year. (Construction Permit 93AD763)

T079: Storage and transfer of gas oil or heavier petroleum products shall not exceed 12,000,000 barrels per year. (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to include throughput limits as requested on the APEN submitted September 10, 2007)

Records of the monthly and annual throughputs for each tank, and other data necessary for calculating emissions, shall be maintained on site and made available to the Division upon request.

16. Group F Tanks – Grandfathered, External Floating Roof Tanks - T035, T036, T044, T052, T054

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	16.1		TANKS or AP-42	Recordkeeping Calculation	Annually
MACT	16.2	See 40 CFR Part 63 Subpart CC		See 40 CFR Part 63 Subpart CC, Condition 32	
RACT	16.3	See Condition 16.3		See Condition 16.3	
Throughput	16.4			Recordkeeping	Monthly

16.1 For APEN reporting and fee purposes, annual emissions shall be calculated using the most recent valid version of the EPA's TANKS program or EPA AP-42 emission factors and actual throughput. Records of emission calculations shall be maintained and made available for inspection upon request. (Colorado Regulation No. 3, Part A, Section II)

16.2 These sources are subject to 40 CFR Part 63, Subpart CC, Standards for Hazardous Air Pollutants from Petroleum Refineries, as set forth in Condition 32 of this permit.

16.3 These sources are subject to Colorado Regulation No. 7, III.A, VI.A.1, and VI.B.2.b and c as set forth in Conditions 23.1, 25.1, 25.2.2, and 25.2.3 of this permit.

16.4 Records of the monthly and annual throughputs for each tank, and other data necessary for calculating emissions, shall be maintained on site and made available to the Division upon request.

17. Group G Tanks – Grandfathered, Internal Floating Roof Tanks - T025, T028, T037, T058

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	17.1		TANKS or AP-42	Recordkeeping Calculation	Annually
MACT	17.2	See 40 CFR Part 63 Subpart CC		See 40 CFR Part 63 Subpart CC, Condition 32	
RACT	17.3	See Condition 17.3		See Condition 17.3	
Throughput	17.4			Recordkeeping	Monthly

17.1 For APEN reporting and fee purposes, annual emissions shall be calculated using the most recent valid version of the EPA's TANKS program or EPA AP-42 emission factors and actual throughput. Records of emission calculations shall be maintained and made available for inspection upon request. (Colorado Regulation No. 3, Part A, Section II)

17.2 These sources are subject to 40 CFR Part 63, Subpart CC, Standards for Hazardous Air Pollutants from Petroleum Refineries, as set forth in Condition 32 of this permit.

17.3 These sources are subject to Colorado Regulation No. 7, III.A, and VI.B.2.a and b as set forth in Conditions 23, 25.2.1 and 25.2,2 of this permit (T028 is not subject to VI.B.2).

17.4 Records of the monthly and annual throughputs for each tank, and other data necessary for calculating emissions, shall be maintained on site and made available to the Division upon request.

18. Fugitive VOC Equipment Leak Emissions with Permitted Limits

F012 - Gas Plant Fugitive Emissions

F034 - Supplemental Environmental Project

F035 - Second Stage of Crude Oil Desalting Project

F031 - Equipment Leaks from Installation of Tank T079

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	18.1	F012: 24.50 tons/year F034: 5.21 tons/year F035: 2.82 tons/year F031: 0.61 tons/year	AP-42 Section 5.1 (EPA 453/R-95-017)	Recordkeeping Calculation	Monthly Annually
Equipment Leaks	18.2	Inspection and Repair		See Regulation No. 7, Section VIII.C, Condition 27.8, 40 CFR Part 63 Subpart CC and 40 CFR Part 60 Subpart GGG, Conditions 32 and 30	

18.1 Emissions of air pollutants shall not exceed the limitation listed in the table above. (Construction Permits gas plant (89AD126), crude oil desalting (98AD0758), and Tank T079 (as provided for under the provisions of Section I, Condition 1.4 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to include emissions as requested on the APEN submitted March 9, 2009)) Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. In the absence of credible evidence to the contrary, compliance with these emission limits will be presumed whenever the permittee is carrying out an approved LDAR programs as required under Conditions 30 and 32 of this permit.

For APEN reporting and fee purposes, annual emissions shall be estimated using the emission factors listed in the table above, and shall be included in the APEN submitted for Plantwide Fugitives.

18.2 Equipment leak emissions associated with these sources are subject to the requirements of Colorado Regulation No. 7, Section VIII.C, 40 CFR Part 60, Subpart GGG and 40 CFR Part 63, Subpart CC, as set forth in Conditions 27.8, 30 and 32 of this permit.

19. Opacity Limits

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Opacity	19.1	Not to exceed 20%, except as provided for in 19.2 and 19.3, below		See provisions for each unit	
	19.2	Certain Operating Conditions - Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
Opacity – Flare	19.3	Not to exceed 30% for more than six (6) minutes in any 60 consecutive minutes		Visual Inspection Method 22	Monthly or quarterly If visible emissions
Opacity- **state-only**	19.4	Not to exceed 20%		See provisions for each unit	

19.1 Except as provided in Condition 19.2 and19.3, below, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20 percent opacity. (Colorado Regulation No. 1, II.A.1)

19.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere of any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30 percent opacity, as measured by EPA Method 9 for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes. (Colorado Regulation No. 1, II.A.4)

19.3 No owner or operator of a smokeless flare or other flare for the combustion of waste gases shall allow or cause emissions into the atmosphere of any air pollutant which is in excess of 30% opacity as measured by EPA Method 9 for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes. (Colorado Regulation No. 1, Section II.A.5)

19.4 No owner or operator subject to the provisions of this regulation may discharge, or cause the discharge into the atmosphere of any particulate matter which is:

Greater than 20% opacity.

(Colorado Regulation No. 6, Part B, II.C.3 – This is a **State-Only** requirement)

This opacity standard applies at all times except during periods of startup, shutdown, or malfunction. (40 CFR Part 60, Subpart A, 60.11 (c.), as adopted by reference in Colorado

Regulation No. 6, Part B, I.A). The permittee is subject to the provisions of 40 CFR Part 60, Subpart A as set forth in Condition 36 of this permit.

19.5 **Opacity Monitoring**

19.5.1 For all fuel burning equipment, in the absence of credible evidence to the contrary, compliance with these opacity limits shall be presumed whenever gaseous fuel is used.

19.5.2 For P004 - FCCU Reactor Generator:

Compliance with the opacity limits will be monitored by means of a COM. The COM shall be maintained and operated in accordance with 40 CFR Part 60.

19.5.3 For P009 – Sulfur Recovery Unit:

At least monthly, the permittee shall perform a visual inspection of the source stack (during daylight hours). Such visual inspection shall be conducted for at least six minutes. A minimum interval of one week shall occur between each monthly inspection. When visible emissions persist for more than six (6) minutes during the monthly inspection, an EPA Reference Method 9 observation shall be performed within one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

In addition, a certified opacity reader shall conduct an EPA Reference Method 9 observation on a quarterly basis (during daylight hours). A minimum interval of at least one month shall occur between each quarterly observation. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

19.5.4 For P011 – Cooling Tower

Compliance with the opacity limits shall, in the absence of credible evidence to the contrary, be assumed when the cooling tower is operated in accordance with manufacturer's recommendations and good engineering practices. Such practices shall be in written form and made available for Division inspection upon request.

19.5.5 For: P014 – FCCU Catalyst Loading; F029 – Polymerization Unit Catalyst Unloading, F009 – Polymerization Unit Catalyst Loading; and F030 – Reformer Catalyst Loading

In absence of credible evidence to the contrary, compliance with the opacity limits shall be assumed when established standard operating procedures (SOP) minimizing visible emissions are followed. These SOP shall be in written form and made available to the Division for inspection upon request. Except for F030, Reformer Catalyst Loading, semi-annual EPA Reference Method 9 opacity readings shall be conducted while the loading/unloading activity is taking place, and recorded by a certified reader. A minimum interval of at least four months shall occur between semiannual observations. For F030, Reformer Catalyst Loading, a Reference Method 9 opacity reading shall be conducted each time catalyst is loaded. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit. Cessation of catalyst loading represents credible evidence that an exceedance has ended.

Records of the date and time of each loading/unloading activity shall be maintained on site for Division inspection upon request.

For all sources listed above in Conditions 19.5.1 through 19.5.5, records of the results of EPA Reference Method 9 readings and a copy of the EPA Reference Method 9 reader's certification shall be kept on site and made available to the Division upon request. Copies of any observations exceeding the applicable standard(s) shall be submitted with the next scheduled report.

19.5.6 For flares: In the absence of credible evidence to the contrary, compliance with this opacity limit shall be presumed whenever the provisions set forth in Condition 37 of this permit are met.

20. Particulate Matter Emission Limits – Fuel Burning Equipment

20.1 No owner or operator shall cause or permit to be emitted into the atmosphere from any fuel burning equipment, particulate matter in the flue gases which exceeds the following:

For fuel burning equipment with designed heat inputs greater than 1×10^6 BTU per hour, but less than or equal to 500×10^6 BTU per hour, the following equation will be used to determine the allowable particulate emission limitation.

$PE = 0.5(FI)^{-0.26}$

Where: PE = Particulate Emission in Pounds per million BTU heat input.

FI = Fuel Input in Million Btu per hour.

(Colorado Regulation No. 1, III.A.1.b)

In the absence of credible evidence to the contrary, compliance with this emission limit shall be presumed whenever gaseous fuel is used.

20.2 No owner or operator subject to the provisions of this regulation may discharge, or cause the discharge into the atmosphere of any particulate matter which is:

For fuel burning equipment generating greater than one million Btu but less than 250 million Btu per hour heat input, the following equation will be used to determine the allowable particulate emission limitation:

$PE = 0.5(FI)^{-0.26}$

Where: PE is the allowable particulate emissions in pounds per million Btu heat input
FI is the fuel input in million Btu per hour
(Colorado Regulation No. 6, Part B, II.C.2 – This is a **State-Only** requirement)

This emission limit applies at all times except during periods of startup, shutdown, or malfunction. (40 CFR Part 60, Subpart A, 60.11(c), as adopted by reference in Colorado Regulation No. 6, Part B, I.A). The permittee is subject to the provisions of 40 Part 60, Subpart A, as set forth in Condition 36 of this permit.

In the absence of credible evidence to the contrary, compliance with this emission limit is presumed whenever gaseous fuel is used.

21. Particulate Matter Emission Limits – Manufacturing Processes

21.1 No owner or operator of a manufacturing process unit shall cause or permit emission of any particulate matter into the atmosphere during any consecutive sixty (60) minute period which is in excess of the following.

For process equipment having process weight rates of greater than 30 tons per hour, the allowable emission rate shall be determined by use of the equation:

$PE = 17.31(P)^{0.16}$

Where: PE = Particulate Emission rate in lbs. per hour

P = Process weight rate in tons per hour

(Colorado Regulation No. 1, III.C.1.b)

Emissions shall be calculated monthly using the emission factors and methods listed in the table for each unit, and compared to the above emissions limits. Calculated monthly emissions shall be divided by the monthly hours of operation for each subject unit or activity. Records of the hours of operation for each subject unit, and hourly emission calculations shall be maintained on site for Division inspection upon request.

22. Sulfur Dioxide Emission Limits

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
SO_2 Emissions – Colorado Regulation No. 6, Part B (**State-Only**)	22.1	0.3 lb/bbl oil processed	Per Appendix H	Recordkeeping Calculation	Daily Annually
SO_2 Emissions – Colorado Regulation No.1	22.2	0.3 lb/bbl oil processed/day			Daily Monthly
New Source Performance Standards Subpart J	22.5	0.10 gr H_2S/dscf		Continuous Monitor	Continuous per 60.13
Facility Wide	22.3	1926.3 tons/year	Per Appendix H	Recordkeeping Calculation	Monthly Annually

22.1 No owner or operator may discharge, or cause the discharge, into the atmosphere from any petroleum refining facility, sulfur dioxide in excess of 0.3 lb. Sulfur dioxide for the sum of all SO_2 emissions from a given refining facility, per barrel of oil processed. (Colorado Regulation No. 6, Part B, IV.C.2 – this is a **State-Only** requirement)

In addition, the facility is subject to the provisions of 40 CFR Part 60, Subpart A, as adopted by reference in Colorado Regulation No. 6, Part B, Section I.A, as set forth in Condition 36 of this permit. (**State-only** requirement)

In accordance with the procedures set forth in Appendix H of this permit, SO_2 emissions will be calculated for each SO_2 source and compared to the records of oil processed at the refinery. For each month, daily SO_2 emissions will be calculated by the end of the following month, and kept on file.

22.2 New sources of sulfur dioxide shall not emit or cause to be emitted sulfur dioxide in excess of the following process-specific limitations. 0.3 lbs. sulfur dioxide, for the sum of all SO_2 emissions from a given refinery per barrel of oil processed. (Averaged over a daily 24 hour period, i.e. midnight through 23:59.) (Regulation No. 1, Section VI.B.4.e)

In accordance with the procedures set forth in Appendix H of this permit, SO_2 emissions will be calculated for each SO_2 source and compared to the records of oil processed at the refinery. For each month, daily SO_2 emissions will be calculated by the end of the following month, and kept on file.

22.3 Total facility wide emissions shall not exceed 1926.3 tons/year. Compliance with the annual limit shall be determined on a rolling twelve month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. The permittee shall calculate monthly and rolling twelve month total emissions and keep a compliance record on site for Division review. (Construction Permit 12AD032-3)

In accordance with the procedures in Appendix H of this permit, SO_2 emissions will be calculated for each SO_2 source and compared to the records of oil processed at the refinery. SO_2 emissions will be calculated monthly and kept on file.

22.4 Appendix H of this permit contains the approved methods that will be used to monitor compliance with SO_2 emission limits. Appendix H may be modified in accordance with the procedures set forth in Colorado Regulation No. 3, Part C. The Division shall review all proposed changes for approval, and will determine whether or not this permit must be modified or reopened under the provisions of Colorado Regulation No. 3, Part C. Appendix H is federally and state enforceable.

22.5 **40 CFR Part 60, Subpart J – Standards of Performance for Petroleum Refineries**, as adopted by reference in Colorado Regulation No. 6, Part A

22.5.1 No owner or operator subject to the provisions of this subpart shall burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph. (60.104(a)(1)) The refinery flare is subject to this requirement in accordance with the "Compliance Plan for Flaring Devices" required by the "Consent Decree" and Condition 22.5. on or before December 31, 2007. (Consent Decree, No. SA-05-CA-0569, entered November 23, 2005, Paragraph 237)

22.5.2 Monitoring of emissions and operations other than the refinery flare

Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

For fuel gas combustion devices subject to 60.104(a)(1), an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere (except where an H_2S monitor is installed under paragraph (a)(4) of this section). The monitor shall include an oxygen monitor for correcting the data for excess air, and shall meet the requirements set forth in 60.105(a)(3)(i) through (iv). (60.105(a)(3))

In place of an SO_2 monitor in paragraph (a)(3) of this section, an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in any fuel gas combustion device. (60.105(a)(4))

The owner or operator of a fuel gas combustion device is not required to comply with paragraph (a)(3) or (4) of this section for fuel gas streams that are exempt under §

60.104(a)(1) and fuel gas streams combusted in a fuel gas combustion device that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section will be considered inherently low in sulfur content. If the composition of a fuel gas stream changes such that it is no longer exempt under §60.104(a)(1) or it no longer meets one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section, the owner or operator must begin continuous monitoring under paragraph (a)(3) or (4) of this section within 15 days of the change. (60.105(a)(4)(iv))

For the purpose of reports under 60.7(c), periods of excess emissions that shall be determined and reported are defined as follows:

Sulfur dioxide from fuel gas combustion. All rolling 3-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under 60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

All rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf). (60.105(d)(3))

Note: All averages shall be determined as the arithmetic average of the applicable 1-hour averages, e.g., the rolling 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

22.5.3 For the Refinery Flare, the permittee will elect to use one or any combination of following NSPS Subpart J compliance methods (Consent Decree, No. SA-05-CA-0569, entered November 23, 2005, Paragraph 235)

22.5.3.1 Operate and maintain a flare gas recovery system to control continuous or routine combustion in the refinery flare. Use of a flare gas recovery system on the flare obviates the need to continuously monitor and maintain records of hydrogen sulfide in the gas as otherwise required by 40 CFR §§ 60.105(a)(4) and 60.7.

22.5.3.2 Operate the refinery flare as a fuel gas combustion device and comply with NSPS monitoring requirements by use of a CEMS pursuant to 40 CFR § 60.105(a)(4) or with a predictive monitoring system approved by the EPA as an alternative monitoring system pursuant to 40 CFR § 60.13(i). To the extent that the permittee seeks to use an alternative monitoring method at the refinery flare to demonstrate compliance with the limits at 40 CFR § 60.104(a)(1), the permittee may begin to use the method immediately upon submitting the application for approval to use the method, provided that the alternative method for which approval is being sought is the same as or is substantially similar to the method identified as the “Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas” attached as Appendix D of the Consent Decree (No.

SA-05-CA-0569).

22.5.3.3 Eliminate the routes of continuous or intermittent, routinely-generated fuel gases to the refinery flare and operate the Flaring Device such that it receives only process upset gases, fuel gas released as a result of relief valve leakage or gases released due to other emergency malfunctions.

22.5.4 Compliance Plan for the Refinery Flare The permittee will submit a Compliance Plan for the refinery flare to the EPA and the Division by no later than December 31, 2007. (Consent Decree, No. SA-05-CA-0569, entered November 23, 2005, Paragraph 237)

In the Compliance Plan for the refinery flare, the permittee will:

(a) Certify compliance with one or more of the three compliance methods set forth in Condition 22.5.3 and accept NSPS applicability for the Denver Refinery Flare; provided, however, that if the selected compliance method is a flare gas recovery system (22.5.3.1), then the permittee may certify that compliance and acceptance of NSPS applicability will be achieved by no later than December 31, 2008. (Consent Decree, No. SA-05-CA-0569, entered November 23, 2005, Paragraph 238)

(b) Identify the Condition 22.5.2 compliance method(s) used for the Refinery Flare, and

(c) Describe the activities that the permittee has taken or anticipates taking, together with a schedule, to meet the objectives of the Compliance Plan.

22.5.5 Performance Tests By no later than ninety (90) days after bringing the refinery flare into compliance by using the methods in Condition 22.5.3.2, the permittee will conduct a flare performance test pursuant to 40 CFR §§ 60.8 and 60.18, or an EPA-approved equivalent method unless such performance test has previously been performed. In lieu of conducting the velocity test required in 40 CFR § 60.18, the permittee may submit velocity calculations that demonstrate that the refinery flare meets the performance specification required by 40 CFR § 60.18.

22.5.6 The combustion in a Flaring Device of process upset gases or fuel gas that is released to the Flaring Device as a result of relief valve leakage or other emergency malfunctions is exempt from the requirement to comply with 40 CFR § 60.104(a)(1).

The permittee is subject to the latest version of Subpart J, and Subpart J is federally and state enforceable.

Sources subject to this Subpart are also subject to the provisions of 40 CFR Part 60 Subpart A, as adopted by reference in Colorado Regulation No. 6, Part A, as set forth in Section II, Condition 36 of this permit.

23. Reasonably Available Control Technology – General Requirements for Storage and Transfer of Volatile Organic Compounds - Colorado Regulation No. 7, Section III

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Maintenance and Operation of Storage Tanks	23.1	Minimize Vapor Loss		Inspection	Semi-Annually
Transfer	23.2	See Condition 23.2		Inspection	When loading

23.1 Maintenance and Operation of Storage Tanks and Related Equipment (III.A.) The following tanks are subject to this requirement: Group B, Group C, Group D, Group E, Group F, and Group G tanks.

All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves, shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. When an analyzer is used, testing and monitoring shall be conducted as in Colorado Regulation No. 7, Section VIII.C.3.

Monitoring: Except for Group D Tanks, detectable vapor loss shall be determined using one of the methods described above, at least semi-annually. Records of the monitoring method and results shall be maintained for Division inspection upon request. For Group D Tanks, in the absence of credible evidence to the contrary, compliance with this requirement shall be assumed when the vapor pressure of material stored is less than 0.65 psia. Records of the vapor pressures of materials stored in Group D Tanks shall be maintained on site for Division inspection upon request.

23.2 Transfer (excluding Petroleum Liquids) (III.B) Tank T028 is subject to this requirement.

23.2.1 Except as otherwise provided in Colorado Regulation No. 7, all volatile organic compounds transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged of bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

Monitoring: This requirement is met based on the design and construction of T028.

24. Reasonably Available Control Technology – Storage of Highly Volatile Organic Compounds - Colorado Regulation No. 7, Section IV

T050, T051, T060, T061, T063, T064, T066, T067, T068, and T069 are subject to these requirements.

24.1 Highly volatile organic compounds shall be stored:

In a pressure tank which is at all times capable of maintaining working pressures sufficient to prevent vapor loss to the ambient air; or

With methods and/or equipment approved by the Division in writing pursuant to the request of the person owning or operating the storage facility.

24.2 Vapor loss shall be determined visually, by presence of frost or condensation at the point of leakage, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. When an analyzer is used, testing and monitoring shall be conducted as in Colorado Regulation No. 7, Section VIII.C.3.

Monitoring: Detectable vapor loss shall be determined using one of the methods described above, at least semi-annually. Records of the monitoring method and results shall be maintained for Division inspection upon request.

25. Reasonably Available Control Technology for Storage and Transfer of Petroleum Liquid - Colorado Regulation No. 7, Section VI

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Fixed Roof Tanks with Internal Floating Roofs	25.2.1	See Condition 25.2.1		Inspection	Semi-Annually & when out of service
External Surfaces	25.2.2	See Condition 25.2.2			
Seals on External Floating Roof Tanks	25.2.3	See Condition 25.2.3		Inspection	Semi-annually
Transfer at Terminals	25.3	See Condition 25.3		Testing	See Condition 25.3
Transport Vehicles	25.4	See Condition 25.4.1		Inspection	While loading

25.1 General Requirements (VI.A.1)

No person shall build, install, or permit the building or installation of any rotating pump or compressor handling any type of petroleum liquid unless said pump or compressor is equipped with mechanical seals or other equipment of equal efficiency. If reciprocating-type pumps and compressors are used, they shall be equipped with packing glands properly installed, in good working order, and properly maintained so that no detectable emissions occur from the drain recovery systems.

The permittee shall perform an annual inspection to ensure this requirement is met. Records of the date and results of such inspections shall be maintained on site for Division inspection upon request.

25.2 Storage of Petroleum Liquid in Tanks Greater than 151,412 liters (40,000 gallons) – VI.B.2

25.2.1 Storage of petroleum liquids in fixed roof tanks are subject to the requirements of Colorado Regulation No. 7, Section VI.B.2.a. (Group B and Group G Tanks, and T006, T020, T053, and T062 are subject to this condition.) Note: Records of inspection results shall be kept five years.

25.2.2 Above ground storage tanks used for the storage of petroleum liquid shall have all external surfaces coated with a material which has a reflectivity of solar radiation of 0.7 or more. Methods A or B of ASTM E424 shall be used to determine reflectivity. Alternatively, any untinted white paint may be used which is specified by the manufacture for such use.

This provision shall not apply to written symbols or logograms applied to the external surface of the container for purposes of identification provided such symbols do not cover more than 20% of the exposed top and side surface area of the container or more than 18.6 square meters (200 square feet), whichever is less. (Section VI.B.2.b)

25.2.3 Seals on External Floating Roof Tanks – VI.B.2.c

All petroleum liquid storage vessels equipped with external floating roofs, having capacities greater than 150,000 liters (40,000 gallons), located in ozone non-attainment areas, are subject to the requirements of Colorado Regulation No. 7, Section VI.B.2.c. A copy of the complete regulation is attached and is federally and state enforceable. (Group F Tanks and T026, T038, and T047 are subject to this condition. T012 is exempt from the requirements except for the recordkeeping requirements of VI.B.2.c(ii)(C).) (Note: This condition continues to apply for areas designated as attainment/maintenance.)

25.3 Loading Facilities Classified as Terminals – Section VI.C.2 (Truck Loading Docks F024, and Railcar Dock F019 are subject to this condition)

25.3.1 The owner or operator of a terminal subject to this subsection shall equip the terminal with proper loading equipment and shall follow the procedures listed in Colorado Regulation No. 7, Section VI.C.2.b.

25.3.2 Control devices shall meet the applicable requirements including recordkeeping of subsections IX.A.3.a,b,c, and e, and IX.A.8.a and b. of Colorado Regulation No. 7. In lieu of the requirements in Regulation No. 7, compliance with the provisions of 40 CFR Part 60, Subpart A, 60.18 is considered compliance with the Section IX.A.3 and 8 provisions.

25.3.3 The applicable methods of 40 CFR 60.503, or EPA reference methods 1 through 4, 25A, and 25B of 40 CFR Part 60 shall be used to determine the efficiency of control devices. In lieu of the requirements in Regulation No. 7, compliance with the provisions of 40 CFR Part 60, Subpart A, 60.18 is considered compliance with this condition.

25.3.4 The methods set forth in Appendix A of EPA-450/2-77-026, "Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals" shall be used to test emission points other than control devices.

25.4 Transport Vehicles – Section VI.C.4.a (Railcar Dock F019 is subject to this condition.)

25.4.1 Rail cars shall be loaded only at facilities which allow for the items listed in Section VI.C.4.a.

An inspection shall be performed while loading to ensure the requirements are in place.

26. Reasonably Available Control Technology for Crude Oil – Colorado Regulation No. 7, Section VII

(Tanks 6, 26, and 38 are subject to this provision)

26.1 Storage

Except as provided in Colorado Regulation No. 7, Section VII.A.2, crude oil stored in tanks greater than 151,412 liters (40,000 gallons) shall be subject to the provisions of Colorado Regulation No. 7, Section VI, B.1.b and B.2. (See Condition 25.2 of this permit.)

The permittee is subject to all applicable requirement of Section VII, and Section VII is federally and state enforceable.

27. Reasonably Available Control Technology for Petroleum Refineries - Colorado Regulation No. 7, Section VIII

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Wastewater Separators	27.1	Control Device and closed openings		Condition 27.1.2: Inspection	Seals: Annually Doors and other openings: Semiannually
Process Unit Turnarounds	27.2	See Condition 27.2		As set forth in Division approved procedure	
Blowdown System and Relief Valve Venting	27.3	90% combustion efficiency		See Conditions 27.6 and 27.7	
Vacuum Producing Systems	27.4	See Condition 27.4		See Conditions 27.6 and 27.7	
Sampling, Testing, and Measuring Ports	27.5	Kept in closed position except when being used		Inspection	Continuous
Flare Operation	27.6	See Condition 37.		Visual Emission Inspection See Condition 37	Monthly/ Quarterly
Equipment Leaks	27.8	Inspection and Repair		Inspection and Repair	See Section VIII.C.4

27.1 Wastewater (Oil/Water) Separators (API Separators F021, F022, and F023 are subject to this condition.)

27.1.1 The owner or operator of any wastewater (oil/water) separators at a petroleum refinery shall equip the forebays and separator sections of the wastewater separators with one or more of the emission control devices listed in Section VIII.A.2.a.

27.1.2 The owner or operator of any wastewater (oil/water) separators at a petroleum refinery shall equip all openings in covers, separators, and forebays with lids or seals such that the lids or seals are in the closed position at all times except when in actual use. Access for gauging and sampling shall be minimized. (Section VIII.A.2.b)

Compliance with 27.1.2 shall be monitored by annual inspection of roof seals and semiannual inspection of access doors and other openings. Procedures for inspection shall be in written form, available for Division inspection upon request. Records of inspections shall be maintained for inspection upon request.

27.2 The owner or operator of a petroleum refinery shall develop and submit to the Division for approval a detailed procedure for minimization of volatile organic compound emissions during process unit turnaround. As a minimum, the procedure shall provide for:

Depressurization venting of the process unit or vessel to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency.

No emission of volatile organic compounds from a process unit or vessel until its internal pressure is 17.2 psia or less; and

Recordkeeping of the following items. Records shall be kept for at least five years and shall be made available to the Division for review upon request.

Every date that each process unit is shut down.

The approximate vessel volatile organic compound concentration when the volatile organic compounds were first discharged to the atmosphere.

The approximate total quantity of volatile organic compounds emitted to the atmosphere.

(Colorado Regulation No. 7, VIII.B.2 – procedure was submitted in 1994)

27.3 Venting of blowdown systems and safety pressure relief valves

All blowdown systems, process equipment vents, and pressure relief valves shall be vented to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency. (Section VIII.B.3)

27.4 The owner or operator of any vacuum-producing system at a petroleum refinery shall not permit the emission of any noncondensible volatile organic compounds from the condensers, hot wells or accumulators of the system. This emission limit shall be achieved by venting the noncondensible vapors to a flare or other combustion device, or compressing the vapors and adding them to the refinery fuel gas.

27.5 All sampling, testing, and measuring ports, hatches, and access openings shall be kept in a closed sealed position except during actual sampling or access. (Section VIII.B.5)

27.6 Control devices shall meet the applicable requirements, including recordkeeping, of Colorado Regulation No. 7, Section IX.A.3.a,b,c, and e, and IX.A.8.a and b. (Section VIII.B.6) In lieu of the requirements in Regulation No. 7, compliance with the provisions of 40 CFR Part 60, Subpart A, 60.18 is considered compliance with the Section IX.A.3 and 8 provisions.

27.7 The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60, shall be used to determine the efficiency of control devices. (Section VIII.B.7) In lieu of the requirements in Regulation No. 7, compliance with the provisions of 40 CFR Part 60, Subpart A, 60.18 is considered compliance with this condition.

27.8 Petroleum Refinery Equipment Leaks (Section VIII.C)

27.8.1 The owner or operator of a petroleum refinery complex subject to this regulation shall meet the requirements set forth in VIII.C.2.a.

27.8.2 Except for safety pressure relief valves, no owner or operator of a petroleum refinery shall install or operate a valve at the end of a pipe or line containing volatile organic compounds unless the pipe or line is sealed with a second valve, a blind flange, a plug, or a cap. The sealing device may be removed only when a sample is being taken or when the valve is otherwise in use. (VIII.C.2.b)

27.8.3 Piping valves and pressure relief valves in gaseous VOC service shall be marked in some manner that will be readily obvious to both refinery personnel performing monitoring and the Division, to identify them as components which are monitored quarterly. (VIII.C.2.d)

27.8.4 Testing and calibration procedures to determine compliance with this regulation shall be consistent with EPA reference method 21 of 40 CFR Part 60. The reference compound may be methane or hexane. A leak is defined as a reading of 10,000 ppmv of the reference compound. (VIII.C.3)

27.8.5 The owner or operator shall meet the recordkeeping and reporting requirements set forth in VIII.C.4.b and c.

28. Reasonably Available Control Technology – Control of Volatile Organic Compound Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities – Section XV

(Truck Loading Docks F024, and Railcar Dock F019 are subject to this condition)

28.1 The operator of a vapor collection or vapor control system at a facility subject to the provisions of this section shall operate the vapor collection system and the gasoline loading equipment in a manner that prevents:

Gauge pressure from exceeding 33.6 torr (18 inches of H_2O) and vacuum from exceeding gauge pressure of minus 11.2 torr (minus 6 inches of H_2O) at the point where the vapor return line on the truck connects with the vapor collection line of the facility.

A reading equal to or greater than 100 percent of the lower explosive limit (LEL, measured as propane) at 2.5 centimeters from a known or potential leak source when measured by the procedures described in Appendix B of “Control of Organic Compound Leaks from Gasoline

Tank Trucks and Vapor Collection Systems," EPA-450/2-78-051, during loading or unloading operations at gasoline dispensing facilities, bulk plants and terminals. Such procedure shall be performed at least annually.

Avoidable liquid leaks from the system during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals.

28.2 Repairs and Modifications

The operator shall within fifteen (15) days, repair and retest a vapor collection or control system that exceeds the pressure limits stated in Condition 28.1, above, excepting that;

Should an applicable facility require modification or repairs that will take longer than fifteen (15) days to complete, the operator shall submit to the Division for approval a schedule which includes dates of commencement and completion.

29. Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels), 40 CFR Part 60, Subpart Kb

T006, T020, T026, T046, T047, T053, and T062 are subject to these requirements.

29.1 The owner or operator of each storage vessel meeting the design capacity specifications and vapor pressure requirements of 60.112b(a) shall equip each storage vessel with one of the items listed in 60.112b(a).

29.2 The owner or operator of each storage vessel meeting the design capacity specifications and vapor pressure requirements of 60.112b(b) shall equip each storage vessel with one of the items listed in 60.112b(b).

29.3 **Testing and procedures**

The owner or operator shall comply with the testing and procedures are set forth in 60.113b.

29.4 **Reporting and recordkeeping requirements**

The owner or operator of each storage vessel as specified in 60.112b(a) shall keep records and furnish reports as required by 60.115b (a), (b), or (c) depending upon the control equipment installed to meet the requirements of 60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by 60.115b(c)(1) for at least five years. The record required by (c)(1) will be kept for the life of the control equipment. (60.115b)

After installing a closed vent system and flare to comply with 60.112b, the owner or operator shall meet the requirements set forth in 60.115b(d).

29.5 **Monitoring of operations**

The owner or operator shall comply with the monitoring requirements are set forth in 60.116b.

The permittee is subject to the latest version of Subpart Kb, and Subpart Kb is federally and state enforceable.

29.6 Sources subject to this Subpart are subject to the provisions of 40 CFR Part 60, Subpart A, as set forth in Condition 36 of this permit, except as provided in 40 CFR Part 60, Subpart Kb.

30. 40 CFR Part 60, Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

The following sources are subject to these requirements: F001 – Crude Unit Fugitives; F012 – Gas Plant Fugitives; and F018 - Refinery Flare Fugitives.

30.1 Each owner or operator subject to the provisions of this subpart shall comply with the requirements of 40 CFR Part 60, Subpart VV, 60.482-1 through 60.482-10. (60.592(a))

30.2 An owner or operator may elect to comply with the requirements of 60.483-1 and 60.483-2. (60.592(b)

Test Methods and Procedures

Each owner or operator subject to the provisions of this subpart shall comply with the provisions of 40 CFR Part 60, Subpart VV, 60.485 except as provided in 60.593. (60.592(d))

Recordkeeping and Reporting Requirements

Each owner or operator subject to the provisions of this subpart shall comply with the provisions of 60.486 and 60.487. (60.592(e))

30.3 Sources subject to this Subpart are subject to the provisions of 40 CFR Part 60, Subpart A, as set forth in Condition 36 of this permit, except that 60.7(b) and (c) do not apply.

The complete text of Subparts GGG and VV are attached to this permit, and are federally and state enforceable.

31. Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems – 40 CFR Part 60, Subpart QQQ

Gas Plant Sewers (F011), Upper API (F021), and Sour Water Stripper Sewers (F025) are subject to these requirements.

Standards: General (60.692-1)

Each owner of operator subject to the provisions of this subpart shall comply with the requirements of 60.692-1 to 60.692-5 and with 60.693-1 and 60.693-2, except during periods of startup, shutdown, or malfunction.

Compliance with 60.692-1 to 60.692-5 and with 60.693-1 and 60.693-2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in 60.696.

Standards: Individual drain systems (60.692-2) (F011 and F025)

31.1 Each drain shall be equipped with water seal controls. (60.692-2(a)(1))

31.2 Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls. (60.692-2(a)(2))

31.3 Except as provided in 60.692-2(a)(4), each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.(60.692-2(a)(3))

31.4 As an alternative to the requirements in 60.692(a)(3), if an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of service, inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed. (60.692-2(a)(4))

31.5 Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in 60.692-6. (60.692-2(a)(5))

31.6 Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter. (60.692-2(b)(1))

31.7 Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance. (60.692-2(b)(2))

31.8 Junction boxes shall be visually inspected initially and semiannually thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge. (60.692-2(b)(3))

31.9 If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in 60.692-6. (60.692-2(b)(4))

31.10 Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces. (60.692-2(c)(1))

31.11 The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions. (60.692-2(c)(2))

31.12 Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in 60.692-6. (60.692-2(c)(3))

31.13 Except as provided in 60.692-2(e), each modified or reconstructed individual drain system that has a catch basin in the existing configuration prior to May 4, 1987 shall be exempt from the provisions of this section. (60.692-2(d))

31.14 Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a down stream catch basin. (60.692-2(e))

Standards: Oil-water separators (60.692-3) (F021)

31.15 Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the specifications set forth in 60.692-3(a), except as provided in 60.692-3(d) or in 60.693-2. (60.692-3(a))

31.16 Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per section (250 gpm) of refinery wastewater shall, in addition to the requirements in 60.692-3(a), be equipped and operated with a closed vent system and control device, which meet the requirements of 60.692-5, except as provided in 60.692-2(c) and 60.693-2. (60.692-3(b))

31.17 Each modified or reconstructed oil-water separator tank with a maximum design capacity to treat less than 38 liters per second (600 gpm) of refinery wastewater which was equipped and operated with a fixed roof covering the entire separator tank or a portion of the separator tank prior to May 4, 1987 shall be exempt from the requirements of 60.692-3(b), but shall meet the requirements of 60.692-3(a), or may elect to comply with 60.692-3(c)(2). (60.692-3(c)(1))

31.18 Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of this subpart. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of 60.692-3(a). (60.692-3(e))

Standards: Delay of repair (60.692-6)

31.19 Delay of repair of facilities that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown. (60.692-6(a))

31.20 Repair of such equipment shall occur before the end of the next refinery or process unit shutdown. (60.692-6(b))

Recordkeeping requirements (60.697)

31.21 Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements set forth in 60.697, as applicable. All records shall be retained for a period of 5 years after being recorded unless otherwise noted. (60.697(a), revised to require record retention of five years, for operating permit purposes.)

Reporting Requirements (60.698)

31.22 A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually to the Division. (60.698(c))

The permittee is subject to the latest version of Subpart QQQ, and Subpart QQQ is federally and state enforceable.

31.23 Sources subject to this Subpart are subject to the provisions of 40 CFR Part 60, Subpart A, as set forth in Condition 36 of this permit, except a provided in 40 CFR Part 60, Subpart QQQ.

32. 40 CFR Part 63, Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

General Standards (63.642)

Sources subject to this subpart are also subject to the requirements of 40 CFR Part 63, Subpart A, as set forth in 63.642(c), including, but not limited to, the following.

32.1 No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment, or process to conceal an emission that would otherwise constitute noncompliance with a relevant standard. Such concealment includes, but is not limited to – (1) The use of diluents to achieve compliance with a relevant standard based on the concentration of a pollutant in the effluent discharged to the atmosphere; (2) The use of gaseous diluents to achieve compliance with a relevant standard for visible emissions; and (3) The fragmentation of an operation such that the operation avoids regulation by a relevant standard.(63.4(b))

32.2 At all times, including periods of startup, shutdown, and malfunction, owners or operators shall operate and maintain any affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions at least to levels required by all relevant standards.(63.6(e)(1)(i))

32.3 Malfunctions shall be corrected as soon as practicable after their occurrence in accordance with the startup, shutdown, and malfunction plan required in 63.6(e)(3).(63.6(e)(1)(ii))

32.4 The owner or operator of an affected source shall develop and implement a written startup, shutdown, and malfunction plan in accordance with 63.6(e)(3).

32.5 The owner or operator of an affected source shall maintain relevant records for such source of the information set forth in 63.10(b)(2).

32.6 Except as described in Table 6 of 40 CFR Part 63, Subpart CC, the owner or operator shall file startup, shutdown, and malfunction reports as set forth in 63.10(d)(5)(i) and (ii).

32.7 Owners or operators using flares to comply with the provisions of this part shall monitor these control devices to assure that they are operated and maintained in conformance with their designs. Flares shall be operated as set forth in Subpart Cc and 63.11(b).

32.8 Each owner or operator of a source subject to this subpart shall keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in this subpart. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hardcopy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche. (63.642(e)

32.9 The owner or operator of an existing source subject to the requirements of this subpart shall control emissions of organic HAP's to the level specified in 63.642(g). The owner or operator of an existing source shall demonstrate compliance with the emission standard by following the procedures specified in 63.642(k), or as otherwise set forth in 63.642(i).

Storage Vessel Provisions (63.646)

The following tanks are subject to these provisions: Group 1: Group B Tanks, Group F Tanks, and T024, T025, and T038. Group2: Group C Tanks, Group D Tanks, T012, T028, T037, T058 and T079.

32.10 Overlap with storage vessel regulations: After the compliance date for this subpart, a Group 1 or Group 2 storage vessel that is part of an existing source and is also subject to the provisions of 40 CFR Part Kb, is required to comply only with the requirements of 40 CFR Part Kb, except as provided in (n)(8). (The following tanks are subject to 63.640(n): T006, T020, T026, T046, T047, T053, and T062.)

32.11 Each owner or operator of a Group 1 storage vessel subject to this subpart shall comply with the requirements of 63.119 through 63.121 (40 CFR Part 63, Subpart G – National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater, except as provided in 63.646(b) through (l), and as set forth in 63.636(c) through (l). (63.646(a))

Wastewater Provisions (63.647)

32.12 Overlap with other regulations for wastewater: A Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of 40 CFR Part 60, Subpart QQQ is required to comply only with this subpart. (63.640(o)(1))

32.13 Except as provided in 63.647(b), each owner or operator of a Group 1 wastewater stream shall comply with the requirements of 61.140 through 61.355 of 40 CFR Part 61, Subpart FF (Subpart FF is attached to this permit, and is both federally and state enforceable) for each process wastewater stream that meets the definition in 63.641. (63.647(a))

32.14 Each owner or operator required under Subpart FF of 40 CFR Part 61 to perform periodic measurement of benzene concentration in wastewater, or to monitor process or control device operating parameters shall operate in a manner as set forth in 63.647(c).

Equipment Leak Standards (63.648)

The following sources are subject to these requirements: F001 - Crude Unit Fugitives; F002 – FCCU Fugitives; F005 – Hydrotreater Fugitives; F007 – Reformer Fugitives; F010 – Polymerization Unit Fugitives; F012 – Gas Plant Fugitives; F013 – Amine Unit and Fuel Gas System; F014 – Utilities Fuel Gas System; F017 – Truck Loading Docks; F026 – Truck Docks/R/C Docks; and equipment leaks as defined in Subpart CC associated with Group B Tanks; Group F Tanks; Group G Tanks; T006; T020; T026; and T038.

32.15 Overlap with other regulations for equipment leaks: Equipment leaks that are also subject to the provisions of 40 CFR Part 60 and 61 are required to comply only with the provisions specified in this subpart. (63.640(p))

32.16 Each owner or operator of an existing source subject to the provisions of this subpart shall comply with the provisions of 40 CFR Part 60, Subpart VV and 63.648(b) except as provided in 63.648(a)(1), (a)(2), and 63.648(c) through (i). (63.648(a))

Gasoline Loading Rack Provisions (63.650)

The following sources are subject to these requirements: Truck Loading Docks F024; and the rail car dock (F019).

32.17 Except as provided in 63.650(b) through (c), each owner or operator of a gasoline loading rack classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a petroleum refinery shall comply with 40 CFR Part 63, Subpart R, as set forth in 63.650(a).

Reporting and Recordkeeping Requirements (63.654)

32.18 Each owner or operator subject to the wastewater provisions in 63.647 shall comply with the recordkeeping and reporting provisions in 40 CFR Part 61, Subpart FF, 61.356 and 61.357 unless they are complying with the wastewater provisions specified in 63.640(o)(2)(ii). There are no additional reporting and recordkeeping requirements for wastewater under this subpart unless a wastewater stream is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in 63.653 and in 63.654(f)(5) and (g)(8). (63.654(a))

32.19 Each owner or operator subject to the gasoline loading rack provisions in 63.650 shall comply with the recordkeeping and reporting provisions in 63.428(b) and (c), (g)(1), and (h)(1) through (h)(3) of 40 CFR Part 63, Subpart R. These requirements are summarized in Table 4 of Subpart CC. There are no additional reporting and recordkeeping requirements for gasoline loading rack under this subpart unless a loading rack is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in 63.653 and in 63.654(f)(5) and (g)(8). (63.654(b))

32.20 Each owner or operator subject to the equipment leak standards in 63.648 shall comply with the recordkeeping and reporting provisions in 63.654(d)(1) through (d)(6). (63.654(d))

32.21 The owner or operator of a source subject to this subpart shall submit Periodic Reports no later than 60 days after the end of each 6-month period when any of the compliance exceptions specified in 63.654(g)(1) through g(6) occur. A Periodic Report is not required if none of the compliance exceptions specified in 63.654(g)(1) through g(6) occurred during the 6-month period unless emissions averaging is utilized. An owner or operator may submit reports required by other regulations in place of or as part of the Periodic Report required by this paragraph if the reports contain the information required in 63.654(g)(1) through (g)(8). (63.654(g))

32.22 Other reports shall be submitted as specified in 40 CFR Part 63, Subpart A and as follows:

Reports of startup, shutdown, and malfunction required by 63.10(d)(5), as set forth in 63.654(h)(1).

For storage vessels, notifications of inspections as specified in 63.654(h)(2).

An owner or operator may request approval to use alternatives to the continuous operating parameter monitoring and recordkeeping provisions listed in 63.654(h)(5)(i).

The owner or operator shall submit the information specified in 63.654(h)(6)(i) through (iii), as applicable, as set forth in 63.654(h)(6).

32.23 Each owner or operator subject to the storage vessel provisions in 63.646 shall keep the records specified in 63.123 of Subpart G except as provided in 63.654(i)(1).

32.24 Each owner or operator required to report the results of performance tests under 63.654(f) and (g)(7) shall retain a record of all reported results as well as a complete test report, as described in 63.654(f)(2)(ii) for each emission point tested.(63.654(i)(2))

The permittee is subject to the latest version of Subpart CC, and Subpart CC is federally and state enforceable.

33. 40 CFR Part 63, Subpart UUU – National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

When do I have to comply with this subpart? **(63.1563)**

33.1 If you have an existing affected source, you must comply with the emission limitations and work practice standards for existing affected sources in this subpart by no later than April 11, 2005 except as specified in 63.1563(c). (63.1563(b))

33.2 We will grant an extension of compliance for an existing catalytic cracking unit allowing additional time to meet the emission limitations and work practice standards as set forth in 63.1563(c).

33.3 You must meet the notification requirements in 63.1574 according to the schedule in 63.1574 and in 40 CFR Part 63, Subpart A. Some of the notifications must be submitted before the date you are required to comply with the emission limitations and work practice standards in this subpart. (63.1563(e))

What are my requirements for metal HAP emissions from catalytic cracking units? (63.1564)

What emission limitations and work practice standards must I meet? You must:

33.4 Meet each emission limitation in Table 1 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for PM in 60.102, you must meet the emission limitations for NSPS units. If your catalytic cracking unit isn't subject to the NSPS for PM, you can choose from the four options in 63.1564(a)(1)(i) through (iv). (63.1564(a)(1))

33.5 Comply with each operating limit in Table 2 of this subpart that applies to you. (63.1564(a)(2))

33.6 Prepare an operation, maintenance, and monitoring plan according to the requirements in 63.1574(f) and operate at all times according to the procedures in the plan. (63.1564(a)(3))

33.7 The emission limitations and operating limits for metal HAP emissions from catalytic cracking units required in 63.1564(a)(1) and (2) do not apply during periods of planned maintenance preapproved by the Division according to the requirements in 63.1575(j). (63.1564(4))

How do I demonstrate initial compliance with the emission limitations and work practice standard? You must:

33.8 Install, operate, and maintain a continuous monitoring system(s) according to the requirements in 63.1572 and Table 3 of this subpart. (63.1564(b)(1))

33.9 Conduct a performance test for each catalytic cracking unit not subject to the NSPS for PM according to the requirements in 63.1571 and under the conditions specified in Table 4 of this subpart. (63.1564(b)(2))

33.10 Establish a site-specific operating limit in Table 2 of this subpart that applies to you according to the procedures in Table 4 of this subpart. (63.1564(b)(3))

33.11 Use the procedures in 63.1564(b)(4)(i) through (iv) to determine initial compliance with the emission limitations. (63.1564(b)(4))

33.12 Demonstrate initial compliance with each emission limitation that applies to you according to Table 5 of this subpart. (63.1564(b)(5))

33.13 Demonstrate initial compliance with the work practice standard in 63.1564(a)(3) by submitting your operation, maintenance, and monitoring plan to the Division as part of you Notification of Compliance Status. (63.1564(b)(6))

33.14 Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.1574. (63.1564(b)(7))

How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

33.15 Demonstrate continuous compliance with each emission limitation in Tables 1 and 2 of this subpart that applies to you according to the methods specified in Tables 6 and 7 of this subpart. (63.1564(c)(1))

33.16 Demonstrate continuous compliance with the work practice standard in 63.1564(a)(3) by maintaining records to document conformance with the procedures in your operation, maintenance, and monitoring plan. (63.1564(c)(2))

33.17 If you use a continuous opacity monitoring system and elect to comply with Option 3 in 63.1564(a)(1)(iii), determine continuous compliance with your site-specific Ni operating limit by using Equation 11 of this section as set forth in 63.1564(c)(3).

33.18 If you use a continuous opacity monitoring system and elect to comply with Option 4 in 63.1564(a)(iv), determine continuous compliance with your site-specific Ni operating limit by using Equation 12 as set forth in 63.1564(c)(4).

What are my requirements for organic HAP emissions from catalytic cracking units? (63.1565)

What emission limitations and work practice standards must I meet? You must:

33.19 Meet each emission limitation in Table 8 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for carbon monoxide (CO) in 60.103, you must meet the emission limitations for NSPS units. If your catalytic cracking unit isn’t subject to the NSPS for CO, you can choose from the two options in 63.1565(a)(1)(i) through (ii). (63.1565(a)(1))

33.20 Comply with each site-specific operating limit in Table 9 of this subpart that applies to you. (63.1565(a)(2))

33.21 Prepare an operation, maintenance, and monitoring plan according to the requirements in 63.1574(f) and operate at all times according to the procedures in the plan. (63.1565(a)(3))

33.22 The emission limitations and operating limits for organic HAP emissions from catalytic cracking units required in 63.1565(a)(1) and (2) do not apply during periods of planned maintenance preapproved by the Division according to the requirements in 63.1575(j). (63.1565(a)(4))

How do I demonstrate initial compliance with the emission limitations and work practice standards? You must:

33.23 Install, operate, and maintain a continuous monitoring system according to the requirements in 63.1572 and Table 10 of this subpart. Except as set forth in 63.1565(b)(1)(i) through (iii). (63.1565(b)(1))

33.24 Conduct each performance test for a catalytic cracking unit not subject to the NSPS for CO according to the requirements in 63.1571 and under the conditions specified in Table 11 of this subpart. (63.1565(b)(2))

33.25 Establish each site-specific operating limit in Table 9 of this subpart that applies to you according to the procedures in Table 11 of this subpart. (63.1565(b)(3))

33.26 Demonstrate initial compliance with each emission limitation that applies to you according to Table 12 of this subpart. (63.1565(b)(4))

33.27 Demonstrate initial compliance with the work practice standard in 63.1565(a)(3) by submitting the operation, maintenance, and monitoring plan to the Division as part of your Notification of Compliance Status according to 63.1574. (63.1565(b)(5))

33.28 Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.1574. (63.1565(b)(6))

How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

33.29 Demonstrate continuous compliance with each emission limitation in Tables 8 and 9 of this subpart that applies to you according to the methods specified in Tables 13 and 14 of this subpart. (63.1565(c)(1))

33.30 Demonstrate continuous compliance with the work practice standard in 63.1565(a)(3) by complying with the procedures in your operation, maintenance, and monitoring plan. (63.1565(c)(2))

What are my requirements for organic HAP emissions from catalytic reforming units? (63.1566)

What emission limitations and work practice standards must I meet? You must:

33.31 Meet each emission limitation in Table 15 of this subpart that applies to you. You can choose from the two options in 63.1566(a)(1)(i) through (ii). (63.1566(a)(1))

33.32 Comply with each site-specific operating limit in Table 16 of this subpart that applies to you. (63.1566(a)(2))

33.33 The emission limitations in Tables 15 and 16 of this subpart apply to emissions from catalytic reforming unit process vents that occur during depressuring and purging operations. These process vents include those used during unit depressurization, purging, coke burn, catalyst rejuvenation, and reduction or activation purge. (63.1566(a)(3))

33.34 The emission limitations in Tables 15 and 16 of this subpart do not apply during depressuring and purging operations when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less. (63.1566(a)(4))

33.35 Prepare an operation, maintenance, and monitoring plan according to the requirements in 63.1574(f) and operate at all times according to the procedures in the plan. (63.1566(a)(5))

How do I demonstrate initial compliance with the emission limitations and work practice standards? You must:

33.36 Install, operate, and maintain a continuous monitoring system(s) according to the requirements in 63.1572 and Table 17 of this subpart. (63.1566(b)(1))

33.37 Conduct each performance test for a catalytic reforming unit according to the requirements in 63.1571 and under the conditions specified in Table 18 of this subpart. (63.1566(b)(2))

33.38 Establish each site-specific operating limit in Table 16 of this subpart that applies to you according to the procedures in Table 18 of this subpart. (63.1566(b)(3))

33.39 Use the procedures in 63.1566(b)(4)(i) or (ii) to determine initial compliance with the emission limitations. (63.1566(b)(4))

33.40 If you elect the 20 parts per million by volume (ppmv) concentration limit, correct the measured TOC concentration for oxygen (O2) content in the gas stream using Equation 4 of this section as set forth in 63.1566(b)(5).

33.41 You are not required to do a TOC performance test if you meet the requirements in 63.1566(b)(6).

33.42 Demonstrate initial compliance with each emission limitation that applies to you according to Table 19 of this subpart. (63.1566(b)(7))

33.43 Demonstrate initial compliance with the work practice standard in 63.1566(a)(5) by submitting the operation, maintenance, and monitoring plan to the Division as part of your Notification of Compliance Status. (63.1566(b)(8))

33.44 Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.1574. (63.1566(b)(9))

How do I demonstrate continuous compliance with the emission l imitations and work practice standards? You must:

33.45 Demonstrate continuous compliance with each emission limitation in Tables 15 and 16 of this subpart that applies to you according to the methods specified in Tables 20 and 21 of this subpart. (63.1566(c)(1))

33.46 Demonstrate continuous compliance with the work practice standards in 63.1566(a)(3) by complying with the procedures in your operation, maintenance, and monitoring plan. (63.1566(c)(2))

What are my requirements for inorganic HAP emissions from catalytic reforming units? (63.1567)

What emission limitations and work practice standards must I meet? You must:

33.47 Meet each emission limitation in Table 22 of this subpart that applies to you. These emission limitations apply during coke burn-off and catalyst rejuvenation. You can choose from the two options in 63.1567(a)(1)(I) through (ii). (63.1567(a)(1))

33.48 Meet each site-specific operating limit in Table 23 of this subpart that applies to you. These operating limits apply during coke burn-off and catalyst rejuvenation. (63.1567(a)(2))

33.49 Prepare an operation, maintenance, and monitoring plan according to the requirements in 63.1574(f) and operate at all times according to the procedures in the plan. (63.1567(a)(3))

How do I demonstrate initial compliance with the emission limitations and work practice standard? You must:

33.50 Install, operate, and maintain a continuous monitoring system(s) according to the requirements in 63.1572 and Table 24 of this subpart. (63.1567(b)(1))

33.51 Conduct each performance test for a catalytic reforming unit according to the requirements in 63.1571 and the conditions specified in Table 25 of this subpart. (63.1567(b)(2))

33.52 Establish each site-specific operating limit in Table 23 of this subpart that applies to you according to the procedures in Table 25 of this subpart. (63.1567(b)(3))

33.53 Demonstrate initial compliance with each emission limitation that applies to you according to Table 26 of this subpart. (63.1567(b)(4))

33.54 Demonstrate initial compliance with the work practice standard in 63.1567(a)(3) by submitting the operating, maintenance, and monitoring plan to the Division as part of you Notification of Compliance Status. (63.1567(b)(5))

33.55 Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.1574. (63.1567(b)(6))

How do I demonstrate continuous compliance with the emission limitations and work practice standard? You must:

33.56 Demonstrate continuous compliance with each emission limitation in Tables 22 and 23 of this subpart that applies to you according to the methods specified in Tables 27 and 28 of this subpart. (63.1567(c)(1))

33.57 Demonstrate continuous compliance with the work practice standard in 63.1567(a)(3) by maintaining records to document conformance with the procedures in you operation, maintenance and monitoring plan. (63.1567(c)(2))

What are my requirements for HAP emissions from sulfur recovery units? (63.1568)

What emission limitations and work practice standard must I meet? You must:

33.58 Meet each emission limitation in Table 29 of this subpart that applies to you. If your sulfur recovery unit is subject to the NSPS for sulfur oxides in 60.104, you must meet the emission limitations for NSPS units. If your sulfur recovery unit isn't subject to the NSPS for sulfur oxides, you can choose from the options in 63.1568(a)(1)(i) through (ii). (63.1568(a)(1)

33.59 Meet each operating limit in Table 30 of this subpart that applies to you. (63.1568(a)(2))

33.60 Prepare an operation, maintenance, and monitoring plan according to the requirements in 63.1574(f) and operate at all times according to the procedure in the plan. (63.1568(a)(3))

How do I demonstrate initial compliance with the emission limitations and work practice standards? You must:

33.61 Install, operate, and maintain a continuous monitoring system according to the requirements in 63.1572 and Table 31 of this subpart. (63.1568(b)(1))

33.62 Conduct each performance test for a sulfur recovery unit not subject to the NSPS for sulfur oxides according to the requirements in 63.1571 and under the conditions specified in Table 32 of this subpart. (63.1568(b)(2))

33.63 Establish each site-specific operating limit in Table 30 of this subpart that applies to you according to the procedures in Table 32 of this subpart. (63.1568(b)(3))

33.64 Correct the reduced sulfur samples to zero percent excess air using Equation 1 of this section as set forth in 63.1568(b)(4).

33.65 Demonstrate initial compliance with each emission limitation that applies to you according to Table 33 of this subpart. (63.1568(b)(5))

33.66 Demonstrate initial compliance with the work practice standard in 63.1568(a)(3) by submitting the operating, maintenance, and monitoring plan to the Division as part of your Notification of Compliance Status. (63.1568(b)(6))

33.67 Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.1574. (63.1568(b)(7))

How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

33.68 Demonstrate continuous compliance with each emission limitation in Tables 29 and 30 of this subpart that applies to you according to the methods specified in Tables 34 and 35 of this subpart. (63.1568(c)(1))

33.69 Demonstrate continuous compliance with the work practice standard in 63.1568(a)(3) by complying with the procedures in our operation, maintenance, and monitoring plan. (63.1568(c)(2))

What are my requirements for HAP emissions from bypass lines? (63.1569)

What work practice standards must I meet?

33.70 You must meet each work practice standard in Table 36 of this subpart that applies to you. You can choose from the four options in 63.1569(a)(1)(i) through (iv). (63.1569(a)(1))

33.71 As provided in 63.6(g), the EPA may choose to grant you permission to use an alternative to the work practice standard in 63.1569(a)(1). (63.1569(a)(2))

33.72 You must prepare an operation, maintenance, and monitoring plan according to the requirements in 63.1574(f) and operate at all times according to the procedures in the plan. (63.1569(a)(3))

How do I demonstrate initial compliance with the work practice standards? You must:

33.73 If you elect the option in 63.1569(a)(1)(i), conduct each performance test for a bypass line according to the requirements in 63.1571 and under the conditions specified in Table 37 of this subpart. (63.1569(b)(1))

33.74 Demonstrate initial compliance with each work practice standard in Table 36 of this subpart that applies to you according to Table 38 of this subpart. (63.1569(b)(2))

33.75 Demonstrate initial compliance with the work practice standard in 63.1569(a)(3) by submitting the operation, maintenance, and monitoring plan to the Division as part of you Notification of Compliance Status. (63.1569(b)(3))

33.76 Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.1574. (63.1569(b)(4))

How do I demonstrate continuous compliance with the work practice standards? You must:

33.77 Demonstrate continuous compliance with each work practice standard in Table 36 of this subpart that applies to you according to the requirements in Table 39 of this subpart. (63.1569(c)(1))

33.78 Demonstrate continuous compliance with the work practice standard in 63.1569(a)(2) by complying with the procedures in your operation, maintenance, and monitoring plan. (63.1569(c)(2))

What are my general requirements for complying with this subpart? (63.1570)

33.79 You must be in compliance with all of the non-opacity standards in this subpart during the times specified in 63.6(f)(1). (63.1570(a))

33.80 You must be in compliance with the opacity and visible emission limits in this subpart during the times specified in 63.6(h)(1). (63.1570(b))

33.81 You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in 63.6(e)(1)(i). During the period between the compliance date specified for you affected source and the date upon which continuous monitoring system have been installed and validated and any applicable operating limits have been set, you must maintain a log detailing the operation and maintenance of the process and emissions control equipment. (63.1570(c))

33.82 You must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in 63.6(e)(3). (63.1570(d))

33.83 During periods of startup, shutdown, and malfunction, you must operate in accordance with your SSMP. (63.1570(e))

33.84 You must report each instance in which you did not meet each emission limitation and each operating limit in this subpart that applies to you. This includes periods of startup, shutdown, and malfunction. You also must report each instance in which you did not meet the work practice standards in this subpart that apply to you. These instances are deviations from the emission limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in 63.1575. (63.1570(f))

33.85 Consistent with 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Division’s satisfaction that you were operating in accordance with the SSMP. The SSMP must require that good air pollution control practices are used during those periods. The plan must also include elements designed to minimize the frequency of such periods (i.e. root cause analysis). The Division will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in 63.6(e) and the contents of the SSMP. (63.1570(g))

How and when do I conduct a performance test or other initial compliance demonstration? (63.1571)

When must I conduct a performance test?

33.86 You must conduct performance tests and report the results by no later than 150 days after the compliance date specified for your source in 63.1563 and according to the provisions in 63.7(a)(2). If you are required to do a performance evaluation or test for a semi-regenerative catalytic reforming unit catalyst regenerator vent, you may do them at the first regeneration cycle after your compliance date and report the results in a follow up Notification of Compliance Status Report due no later than 150 days after the test. (63.1571(a))

33.87 For each emission limitation or work practice standard where initial compliance is not demonstrated using a performance test, opacity observation, or visible emission observation, you must conduct the initial compliance demonstration within 30 calendar days after the compliance date that is specified for your source in 63.1563. (63.1571(a)(1))

33.88 For each emission limitation where the averaging period is 30 days, the 30-day period for demonstrating initial compliance begins at 12:00 a.m. on the compliance date that is specified for your source in 63.1563 and ends at 11:59 p.m., 30 calendar days after the compliance date that is specified for your source in 63.1563. (63.1571(a)(2))

What are the general requirements for performance test and performance evaluations? You must:

33.89 Conduct each performance test according to the requirements in 63.7(e)(1). (63.1571(b)(1))

33.90 Except for opacity and visible emission observations, conduct three separate test runs for each performance test as specified in 63.7(e)(3). Each test run must last at least 1 hour. (63.1571(b)(2))

33.91 Conduct each performance evaluation according to the requirements in 63.8(e). 63.1571(b)(3))

33.92 Not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in 63.7(e)(1). (63.1571(b)(4))

33.93 Calculate the average emission rate for the performance test by calculating the emission rate for each individual test run in the units of the applicable emission limitation using Equation 2, 5 or 8 of 63.1564, and determine the arithmetic average of the calculated emission rates. (63.1571(b)(5))

What procedures must I use for an engineering assessment?

33.94 You may choose to use an engineering assessment to calculate the process vent flow rate, net heating value, TOC emission rate, and total organic HAP emission rate expected to yield the highest daily emission rate when determining the emission reduction or outlet concentration for the organic HAP standard for catalytic reforming units. If you use an engineering assessment, you must document all data, assumptions, and procedures to the satisfaction of the Division. An engineering assessment may include the approaches listed in 63.1571(c.)(1) through (4). Other engineering assessments may be used but are subject to review and approval by the Division. (63.1571(c.))

Can I adjust the process or control device measured values when establishing an operating limit?

33.95 If you do a performance test to demonstrate compliance, you must base the process or control device operating limits for continuous parameter monitoring systems on the results measured during the performance test. You may adjust the values measured during the performance test according to the criteria in 63.1571(d)(1) through (3). (63.1571(d))

33.96 Except as specified in 63.1571(d)(3), if you use continuous parameter monitoring systems, you may adjust one of your monitored operating parameters (flow rate, voltage and secondary current, pressure drop, liquid-to-gas ratio) from the average of measured values during the performance test to the maximum value (or minimum value, if applicable) representative of worst-case operating conditions, if necessary. This adjustment of measured values may be done using control device design specifications, manufacturer recommendations, or other applicable information. You must provide supporting documentation and rationale in your Notification of Compliance Status, demonstrating to the satisfaction of the Division, that your affected source complies with the applicable emission l it at the operating limit based on adjusted values. (63.1571(d)(4))

Can I change my operating limit?

33.97 You may change the established operating limit by meeting the requirements in 63.1571(e)(1) through (3).

What are my monitoring installation, operation, and maintenance requirements? (63.1572)

33.98 You must install, operate, and maintain each continuous emission monitoring system according to the requirements in 63.1572(a)(1) through (4).

33.99 You must install, operate, and maintain each continuous opacity monitoring system according to the requirements in 63.1572(b)(1) through (3).

33.100 You must install, operate, and maintain each continuous parameter monitoring system according to the requirements in 63.1572(c.)(1) through (5).

33.101 You must monitor and collect data according to the requirements in 63.1572(d)(1) and (2).

What are my monitoring alternatives? (63.1573)

What is the approved alternative for monitoring gas flow rate?

33.102 You can elect to use the alternative set forth in 63.1573(a) to a continuous parameter monitoring system for the catalytic regenerator exhaust gas flow rate for your catalytic cracking unit if the unit does not introduce any other gas streams into the catalyst regeneration vent (i.e., complete combustion units with no additional combustion devices). If you select this alternative, you must use the same procedure for the performance test and for monitoring after the performance test.

What is the approved alternative for monitoring pH levels?

33.103 If you use a wet scrubber to control inorganic HAP emission from you vent on a catalytic reforming unit, you can measure and record the pH of the water (or scrubbing liquid) exiting the scrubber at least once an hour during coke burn-off and catalyst rejuvenation using pH strips as an alternative to a continuous parameter monitoring system. The pH strips must meet the requirements in Table 41 of this subpart. (63.1573(b))

Can I use another type of monitoring system?

33.104 You may request approval from the Division to use an automated data compression system, as set forth in 63.1573(c.).

Can I monitor other process or control device operating parameters?

33.105 You may request approval to monitor parameters other than those required in this subpart, as set forth in 63.1573(d).

How do I request to monitor alternative parameters?

33.106 You must submit a request for review and approval or disapproval to the Division. The request must include the information in 63.1573(e)(1) through (5).

What notifications must I submit and when? (63.1574)

33.107 Except as allowed in 63.1574(a)(1) through (3), you must submit all of the notifications in 63.6(h), 63.7(b) and (c), 63.8(e), 63.8(f)(4), 63.8(f)(6), and 63.9(b) through (h) that apply to you by the dates specified. (63.1574(a))

33.108 You also must include the information in Table 42 of this subpart in your Notification of Compliance Status. (63.1574(d))

33.109 If you request an extension of compliance for an existing catalytic cracking unit as allowed in 63.1563(c.), you must submit a notification to the Division containing the required information by October 13, 2003. (63.1574(e))

33.110 As required by this subpart, you must prepare and implement an operation, maintenance, and monitoring plan for each affected source, control system, and continuous monitoring system, as set forth in 63.1574(f). The purpose of this plan is to detail the operation, maintenance, and monitoring procedures you will follow. (63.1574(f))

What reports must I submit and when? (63.1575)

33.111 You must submit each report in Table 43 of this subpart that applies to you. (63.1575(a))

33.112 Unless the Division has approved a different schedule, you must submit each report by the date in Table 43 of this subpart according to the requirements in 63.1575(b)(1) through (5).

33.113 The compliance report must contain the information required in 63.1575(c.)(1) through (4).

33.114 For each deviation from an emission limitation and for each deviation from the requirements for work practice standards that occurs at an affected source where you are not using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation or work practice standard in this subpart, the compliance report must contain the information in 63.1575(c.)(1) through (3) and the information in 63.1575(d)(1) through (3).

33.115 For each deviation from an emission limitation occurring at an affected source where you are using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, you must include the information in 63.1575(d)(1) through (3) and the information in 63.1575(e)(1) through (13).

33.116 You also must include the information required in 63.1575(f)(1) through (2) in each compliance report, if applicable.

33.117 You may submit reports required by other regulations in place of or as part of the compliance report if they contain the required information. (63.1575(g))

33.118 The reporting requirements in 63.1575(h)(1) and (2) apply to startups, shutdowns, and malfunctions.

What records must I keep, in what form, and for how long? (63.1576)

33.119 You must keep the records specified in 63.1576(a)(1) through (3).

33.120 For each continuous emission monitoring system and continuous opacity monitoring system, you must keep the records required in 63.1576(b)(1) through (5).

33.121 You must keep the records in 63.6(h) for visible emission observations. (63.1576(c))

33.122 You must keep the records required by Tables 6, 7, 13, and 14 of this subpart (for catalytic cracking units); Tables 20, 21, 27 and 28 of this subpart (for catalytic reforming units); Tables 34 and 35 of this subpart (for sulfur recovery units); and Table 39 of this subpart (for bypass lines) to show continuous compliance with each emission limitation that applies to you. (63.1576(d))

33.123 You must keep a current copy of your operation, maintenance, and monitoring plan onsite and available for inspection. You also must keep records to show continuous compliance with the procedures in your operation, maintenance, and monitoring plan. (63.1576(e))

33.124 You also must keep the records of any changes that affect emission control system performance including, but not limited to, the location at which the vent stream is introduced into the flame zone for a boiler or process heater. (63.1576(f))

33.125 Your records must be in a form suitable and readily available for expeditious review according to 63.10(b)(1). (63.1576(g))

33.126 As specified in 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. (63.1576(h))

33.127 You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 63.10(b)(1). You can keep the records offsite for the remaining 3 years. (63.1576(i))

What parts of the General Provisions apply to me? (63.1577)

33.128 Table 44 of this subpart shows which parts of the General Provisions in 63.1 through 63.15 apply to you. (63.1577)

The permittee is subject to the latest version of Subpart UUU, and Subpart UUU is federally and state enforceable.

34. Production Limit

34.1 Processing of oil at this facility shall not exceed 35,000 barrels per day and 13,775,000 barrels per year. Compliance with the annual limit shall be determined on a rolling twelve month total. By the end of each month a new twelve month total is calculated using the previous twelve months' data. Records of actual processing rate shall be maintained for inspection upon request. (Construction Permit 88AD134)

35. Equipment Leak VOC Emissions

35.1 For APEN reporting and fee purposes, VOC emissions from equipment leaks shall be estimated using the emission factors and procedures set forth in the EPA's 453/R95-017.

36. 40 CFR Part 60, Subpart A - General Provisions

These requirements apply to those sources which are subject to 40 CFR Part 60 or Colorado Regulation No. 6, Part B requirements. For Colorado Regulation No. 6, Part B purposes, these are **state-only** requirements. Subpart A requirements include, but are not limited to, the following.

Notification and Recordkeeping (60.7)

36.1 The owner or operator shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. (60.7(b))

36.2 Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Division semi-annually. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the information set forth in 60.7(c).

36.3 The summary report form shall contain the information and be in the format set forth in 60.7(d).

36.4 Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as set forth in 60.7(f). Note: For operating purposes, records must be retained for five years.

Compliance with Standards and Maintenance Requirements (60.11)

36.5 At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. (60.11(d))

Circumvention (60.12)

36.6 No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere. (60.12)

Monitoring Requirements (60.13)

36.7 All continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to this part, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987. (60.13(a))

36.8 Owners and operators of a CEMS installed in accordance with the provisions of this part, must check and adjust the zero and span drifts at least daily as set forth in 60.13(d).

36.9 Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 60.13(d), all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as set forth in 60.13(e).

36.10 All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part shall be used.(60.13(f))

37. Flare Requirements

37.1 Flares shall be designed for and operated with no visible emissions as determined by methods specified in 60.18(f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. (60.18(c)(1))

37.2 Flares shall be operated with a flame present at all times, as determined by methods specified in 60.18(f). (60.18(c)(2))

37.3 Flares shall be used only when the net heating value of the gas being combusted is determined as set forth in 60.18(c)(3).

37.4 Steam assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in 60.18(f)(4), less than 18.3 m/sec (60 ft/sec), except as provided in 60.18(c)(4)(ii) and (iii). (60.18(c)(4)(i))

37.5 Air-assisted flares shall be designed and operated with an exit velocity as set forth in 60.18(c)(5).

37.6 Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted. (60.18(c)(6))

37.7 Owners or operators of flares shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices (60.18(d))

37.8 Flares used to comply with the provisions of this subpart shall be operated at all times when emissions may be vented to them. (60.18(e))

37.9 To monitor compliance with opacity limits, the permittee shall conduct monthly visible emissions checks to qualitatively assess whether emissions are visible (during daylight hours). Such visible emissions checks shall last a minimum of five minutes. The frequency may be reduced to quarterly if no visible emissions are observed for six consecutive months. The permittee shall revert to monthly observations if any visible emissions are noted during the visible emissions checks. If visible emissions are observed during the monthly or quarterly emissions checks, actions shall be taken to reduce visible emissions to zero as soon as possible. If emissions cannot be reduced to zero, the permittee shall conduct an EPA Reference Method 22 observation within one half hour until opacity is shown to be less than the applicable opacity standard. Records of the visible emission observations, any action(s) taken to reduce emissions to zero, the amount of time taken to reduce emissions to zero, and Method 22 readings shall be maintained and made available to the Division for review upon request.

38. 40 CFR Part 61, Subpart FF – National Emission Standard for Benzene Waste Operations

38.1 Any refinery with a total annual benzene quantity from the facility waste less than 10 megagrams per year is subject to general requirements, monitoring, recordkeeping and reporting requirements based on the total annual benzene quantity emission as described in 40 CFR Part 61, Subpart FF as set forth in 61.355(a)(4).

39. Emission Factors

39.1 The permittee shall comply with the provisions of Regulation No. 3 concerning APEN reporting. Emission factors and/or other emission estimating methods that are specified within this permit can not be adjusted without requiring a permit modification. Emission factors and/or other emission estimating methods used only to comply with the reporting requirements of Regulation No. 3, Part A, Section II can be updated and modified as specified in that Section. These changes by themselves do not require any permitting activities though the resulting emission estimate may trigger permitting activities.

40. Maximum Achievable Control Technology

40.1 The EPA finalized the Maximum Achievable Control Technology (MACT) requirements for Organic Liquids Distribution (nongasoline) on August 25, 2003, and for Industrial, Commercial, and Institutional Boilers and Process Heaters on March 9, 2004. Therefore, if this facility is subject to the requirements, this operating permit will be modified using the appropriate procedure as provided for in Colorado Regulation No. 3, Part C, to include the MACT requirements.

SECTION III - Permit Shield

Regulation No. 3, 5 CCR 1001-5, Part C, §§ I.A.4, V.D. & XIII.B; § 25-7-114.4(3)(a), C.R.S.

1. Specific Non-Applicable Requirements

Based on the information available to the Division and supplied by the applicant, the following parameters and requirements have been specifically identified as non-applicable to the facility to which this permit has been issued. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modification or reconstruction on which construction commenced prior to permit issuance.

Emission Unit Description & Number	Applicable Requirement	Justification
Facility Wide	40 CFR Part 60, Subpart GG, as adopted by reference in Colorado Regulation No. 6, Part A	The refinery does not operate any stationary gas turbines
	40 CFR Part 60, Subpart UU, as adopted by reference in Colorado Regulation No. 6, Part A	No tanks store asphalt at this facility.
	40 CFR Part 63, Subpart F, 63.100 and 63.110, as adopted by reference in Colorado Regulation 8, Part E	The facility does not manufacture as a primary product nor use as a reactant or manufacture as a co-product with other chemicals or organic hazardous air pollutants listed.
	40 CFR Part 60, Subpart NNN, as adopted by reference in Colorado Regulation No. 6, Part A	The facility is not a process unit that produces any chemicals listed in 60.667, and no distillation facility that emits a gas stream directly or indirectly to the atmosphere exists at the facility
	Prevention of Significant Deterioration, Colorado Regulation No. 3, Part D, Section VI	This source was an existing source as of the August 7, 1977 effective date of 40 CFR Part 52, with the exception of the PSD permit issued in February 28, 1979 covering the construction of the Crude Vacuum Unit, Reformer expansion, and required SO_2 control equipment (Claus Unit, Amine Unit, and Tailgas Incinerator)
	40 CFR Part 63 Subpart GGGGG, as adopted by reference in Colorado Regulation No. 8, Part E, “National Emission Standards for Hazardous Air Pollutants: Site Remediation”	Site remediation at the Commerce City Refinery, Plant 2 (East) is required by an order authorized un RCRA Section 7003 as provided for in 40 CFR Part 63 Subpart GGGGG 63.7881(b)(3).
B001 – Crude/Vacuum Process	40 CFR Part 60, Subpart QQQ, as adopted by reference in Colorado Regulation No. 6, Part A	Crude/vacuum unit sewers were constructed prior to the effective date of May 4, 1987
	40 CFR Part 63, Subpart CC, 63.643, 644,and 645 as adopted by reference in Colorado Regulation No. 8, Part E	No equipment associated with the Crude Unit meets the definition of a miscellaneous process vent under Subpart CC
	40 CFR Part 60, Subpart RRR	Unit does not consist of reactor processes and associated recovery systems that produce any of the chemicals listed in 40 CFR 60.707

Emission Unit Description & Number	Applicable Requirement	Justification
B001 – Crude/Vacuum Process	40 CFR Part 60, Subpart VV, as adopted by reference in Colorado Regulation No. 6, Part A (except as required in Subpart GGG)	Unit does not produce the listed chemicals
	40 CFR Part 60, Subpart J – 60.105(a), as adopted by reference in Colorado Regulation No. 6, Part A (Pilot Gas)	Hydrogen used as pilot gas. EPA exempts refinery pilot gas from monitoring requirements when hydrogen is used as a fuel.
P003 – FCCU Process	Colorado Regulation No. 1, IV.D.1	FCCU regenerator is less than 20,000 bbl/day capacity, therefore no opacity monitor is required
	Colorado Regulation No. 1, IV.D.2	As allowed in this regulation, the Division has approved an exemption from this requirement.
	40 CFR Part 60, Subpart J, as adopted by reference in Colorado Regulation No. 6, Part A (FCCU regenerator portions only)	The FCCU regenerator was constructed before June 11, 1973
	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	The FCCU was constructed before January 4, 1983.
	40 CFR Part 60, Subpart QQQ, as adopted by reference in Colorado Regulation No. 6, Part A	The FCCU sewers were constructed prior to the effective date of May 4, 1987.
B002 – FCCU Heater	Colorado Regulation No. 6, Part B, II.C	Construction commenced for the heater prior to January 30, 1979
P003 – FCCU	40 CFR Part 63, Subpart CC, 63.643, 644, and 645, as adopted by reference in Colorado Regulation No. 8, Part E	No equipment associated with the FCCU meets the definition of miscellaneous process vent under Subpart CC
	40 CFR Part 60, Subpart RRR, as adopted by reference in Colorado Regulation No. 6, Part A	The FCCU is a reactor process that is identified in 40 CFR Part 60, Subpart J, and does not produce any chemicals subject to 40 CFR 60.700
	40 CFR Part 60, Subpart J, 60.105(a), as adopted by reference in Colorado Regulation No. 6, Part A (Pilot Gas)	Hydrogen used as a pilot gas. The EPA exempts refinery pilot gas from monitoring requirements when hydrogen is used as a fuel.
P005 – Naphtha/ Dehydrator & Reformer	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	The Naphtha Hydrotreater & Reformer Units were constructed prior to the effective date of January 4, 1983
	40 CFR Part 60, Subpart QQQ, as adopted by reference in Colorado Regulation No. 6, Part A	The Naphtha Hydrotreater & Reformer Units sewers were constructed prior to the effective date of May 4, 1987
	40 CFR Part 63, Subpart CC 63.643, 63.644, 63.645, as adopted by reference in Colorado Regulation No. 8, Part E	No equipment associated with the Naptha Hydrotreater & Reformer Units meets the definition of a miscellaneous process vent under 40 CFR Part 63, Subpart CC
	40 CFR Part 60, Subpart RRR, as adopted by reference in Colorado Regulation No. 6, Part A	Unit does not have a vent stream from the reactor except during periodic catalyst regeneration. In addition, unit's primary products are petroleum liquids used as gasoline blendstock. Finally, unit was constructed prior to the effective date of Subpart RRR.

Emission Unit Description & Number	Applicable Requirement	Justification
P005 – Naphtha/ Dehydrator & Reformer	40 CFR Part 60, Subpart J, 60.105(a), as adopted by reference in Colorado Regulation No. 6, Part A (Pilot Gas)	Hydrogen used as a pilot gas. The EPA exempts refinery pilot gas from monitoring requirements when hydrogen is used as a fuel.
	40 CFR Part 63, Subpart CC, 63.648, as adopted by reference in Colorado Regulation No. 8, Part E	Reformer compressor in hydrogen service and hydrogen content can reasonably be expected always to exceed 50% by volume (63.648(g))
P006 – Polymerization Unit	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	The Polymerization Unit was constructed prior to the effective date of January 4, 1983
	40 CFR Part 60, Subpart QQQ, as adopted by reference in Colorado Regulation No. 6, Part A	The Polymerization Unit was constructed prior to the effective date of May 4, 1987
	40 CFR Part 60, Subpart RRR, as adopted by reference in Colorado Regulation No. 6, Part A	The poly reactor does not produce a vent stream and would not be an affected unit under 40 CFR 60.700(b)
P007 – Gas Plant	Colorado Regulation No. 7, II.C.1.a(i)	The gas plant is an existing source, but is subject to specific sections VIII, therefore II.C. does not apply
	40 CFR Part 60, Subpart A, 60.7(a) and (c) and 60.13, as adopted by reference in Colorado Regulation No. 6, Part A	Unit is not required by a New Source Performance Standard to be equipped with a continuous monitoring system
	40 CFR Part 60, Subpart Kb, as adopted by reference in Colorado Regulation No. 6, Part A	Unit includes only pressure tanks. Pressure tanks designated to operate in excess of 204.9 kPa and without emissions to the atmosphere are not subject to the requirements of Subpart Kb.
	40 CFR Part 60, Subpart H, as adopted by reference in Colorado Regulation No. 6, Part A	Unit complies with 40 CFR Part 60, Subpart VV instead
	40 CFR Part 63, Subpart CC, 63.643, 63.644, 63.645, as adopted by reference in Colorado Regulation No.8, Part E	No equipment associated with the Gas Plant meets the definition of a miscellaneous process vent under Subpart CC
	40 CFR Part 60, Subpart RRR, as adopted by reference in Colorado Regulation No. 6, Part A	Sat and unsat gas plants are not reactor processes that produce chemicals listed in 60.707
P009 – Sulfur Recovery Unit	Regulation No. 1, III.A.1	The SRP is not a furnace, boiler, or other equipment burning fuel solely for the purpose of producing heat.
	Regulation No. 1, IV	Not required by Regulation No. 1 to install a CEM – Source not listed in IV.B, C, D and VII
	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	SRP construction commenced prior to January, 1983
	40 CFR Part 60, Subpart QQQ, as adopted by reference in Colorado Regulation No. 6, Part A	SRP construction commenced prior to May 1987
	40 CFR Part 60, Subpart J, as adopted by reference in Colorado Regulation No. 6, Part A – (Claus Plant requirements – fuel gas requirements apply to tail gas incinerator)	Claus unit <20 LTPD, therefore not an affected unit under this subpart

Emission Unit Description & Number	Applicable Requirement	Justification
P009 – Sulfur Recovery Unit	40 CFR Part 63, Subpart CC, 63.643, 63.644, 63.645, as adopted by reference in Colorado Regulation No. 8, Part E	No equipment associated with the SRP meets the definition of a miscellaneous process vent under 40 CFR Part 63, Subpart CC
	40 CFR Part 60, Subpart RRR, as adopted by reference in Colorado Regulation No. 6, Part A	SRP is a reactor process that is identified in NSPS, Subpart J, and is a unit that does not produce any chemicals subject to 60.700
Utilities – B006, B007, B008	Regulation No. 1, IV.A	Not required by Regulation No. 1 to install a CEM – Source not listed in IV.B, C, D and VII
	Regulation No. 1, IV.B.1 and IV.B.2	Fossil fuel steam fired generators less than 250 mmBtu/hr capacity for each boiler
	40 CFR Part 60, Subparts D and Db, as adopted by reference in Regulation No. 6, Part A	Boilers less than 29 MW (100 mmBtu/hour) heat input.
	40 CFR Part 60, Subpart Dc, 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, and 60.47c	Boilers 2 and 3 constructed before June 1989. Boiler 1 constructed after effective date, however, no boiler combusts coal, coal refuse, or wood as is, therefore not subject to any emission requirement of Subpart Dc
	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	Not a compressor or equipment within a process unit, and the fuel gas system constructed prior to January 4, 1983
	Colorado Regulation No. 6, Part B, II.D.1, 2, and 3	Not a coal-fired or oil fired operation. Not a combustion turbine.
	40 CFR Part 60, Subpart J, 60.105(a), as adopted by reference in Colorado Regulation No. 6, Part A (Pilot Gas)	Hydrogen used as a pilot gas. EPA exempts refinery pilot gas from monitoring requirements when hydrogen is used as a fuel.
Utilities – P011	40 CFR Part 63, Subpart Q, as adopted by reference in Colorado Regulation No. 8, Part E	No cooling tower uses chromium based chemicals on or after September 8, 1994.
F015 & F016 – Crude Oil Loading	40 CFR Part 60, Subpart XX, as adopted by reference in Colorado Regulation No. 6, Part A	Not a gasoline bulk terminal. Crude is brought in via trucks to tanks in refinery.
	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	Crude Unloading does not have a compressor, nor is there equipment within a process unit
	Colorado Regulation No. 7, III.B	Applies only to non-petroleum liquid transfer
	Colorado Regulation No. 7, VI.C.2.b	Not a terminal, crude is only unloaded
	Colorado Regulation No. 7, VI.C.3.b-c	Not a bulk plant
	Colorado Regulation No. 7, VI.C.4.a	No rail car loading
	Colorado Regulation No. 7, VI.C.4.b	No loading of petroleum transport trucks that serve locations required to be equipped with vapor recovery equipment
	Colorado Regulation No. 7, XV and Appendix B	Not a terminal, bulk plant, or gasoline dispensing facility

Emission Unit Description & Number	Applicable Requirement	Justification
F024 – Truck Loading	40 CFR Part 60, Subpart XX, as adopted by reference in Colorado Regulation No. 6, Part A	Not a bulk gasoline terminal that commenced construction on or after December 1980
	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	The trucks dock does not have a compressor, nor is there equipment within a process unit. Construction commenced prior to January 4, 1983
	40 CFR Part 60, Subpart QQQ, as adopted by reference in Colorado Regulation No. 6, Part A	Construction commenced prior to May, 1987
	Regulation No. 7, III and Construction Permit 11AD251, Condition 10	III.B excludes petroleum liquids, and III.C applies to beer production
	Colorado Regulation No. 7, VI.C.3.b-c	Not a bulk plant
	Colorado Regulation No. 7, VI.C.4.a	No rail car loading
	40 CFR Part 63, Subpart CC, 63.643, 63.644, and 63.645, as adopted by reference in Colorado Regulation No. 8, Part E	Applies only to petroleum refining process units. The Truck Loading Docks are not a process unit.
	Colorado Regulation No. 1, III.A.1.b and Colorado Regulation No. 6, Part B, II.C	Unit does not include fuel burning equipment
Refinery Flare	Colorado Regulation No. 1, III.A1.b and Colorado Regulation No. 6, Part B, II.C	Unit does not include fuel burning equipment. Equipment does not burn fuel solely for the purpose of producing heat.
	40 CFR Part 60, Subpart VV (except 60.482-10) as adopted by reference in Colorado Regulation No. 6, Part A	Although the flare is used as a control device, the flare itself is not an affected facility described in 60.480
	Colorado Regulation No. 7, VIII.B.6 and IX.A.8.a	Open flare is not a listed control device that requires continuous monitoring
LPG Plant		
Tanks, Truck Dock, LPG Railcar Docks	Colorado Regulation No. 7, VI.B and VI.C, Construction Permit 989AD031, Condition 2	Only LPG is stored and transferred through this equipment. LPG has a vapor pressure greater than 11.0 psia and therefore is exempt from these regulations.
Tanks, LPG Railcar Dock, Gasoline Loading Railcar Dock, and LPG Truck Loading Dock	Colorado Regulation No. 7, VI.D and 89AD031, Condition 2	Unit does not include transport vehicles. Activities are not associated with a gasoline truck loading facility.
Tanks, Docks, Flare	Colorado Regulation No. 7, III.B	Petroleum liquids are excluded from this regulation.
Flare	Colorado Regulation No. 1, III.A.1.b and Colorado Regulation No. 6, Part B, II.C	Unit does not include fuel burning equipment.
	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	Not a process unit

Emission Unit Description & Number	Applicable Requirement	Justification
Tanks	40 CFR Part 60, Subparts K, Ka, Kb, as adopted by reference in Colorado Regulation No. 6, Part A	Pressure tanks not subject to these storage tank requirements
	40 CFR Part 63, Subpart CC, as adopted by reference in Colorado Regulation No. 8, Part E	Pressure tanks are exempt from Subpart CC requirements.
	40 CFR Part 60, Subpart XX, as adopted by reference in Colorado Regulation No. 6, Part A	Not a bulk gasoline terminal
	40 CFR Part 63, Subpart CC, 63.643, 63.644, and 63.645 (gasoline loading only), as adopted by reference in Colorado Regulation No. 8, Part E	No equipment associated with gasoline loading meets the definition of a miscellaneous process vent under Subpart CC
Flare Pilot Fuel	40 CFR Part 60, Subpart J, as adopted by reference in Colorado Regulation No. 6, Part A	Pilot fuel combustion exempted from Subpart J monitoring requirements by the EPA
	40 CFR Part 60, Subpart QQQ, as adopted by reference in Colorado Regulation No. 6, Part A	Not a process unit that includes an individual drain system, oil/water separator, or aggregate facility
	40 CFR Part 60, Subpart VV, as adopted by reference in Colorado Regulation No. 6, Part A (except as set forth in Subpart GGG)	Unit does not contain components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates
	Colorado Regulation No. 7, XV	Unit does not include a gasoline bulk plant or gasoline dispensing facility or load gasoline into trucks
Wastewater Treatment System	Colorado Regulation No. 1	Unit does not emit particulates, smokes, carbon monoxide, or sulfur oxides
	Colorado Regulation No. 3, Part B	Upper API constructed prior to 1972. Lower API constructed prior to 1951
	40 CFR Part 60, Subpart J, as adopted by reference in Colorado Regulation No. 6, Part A	Unit does not include any FCCU catalyst regenerators, Claus Sulfur Recovery Plants, or fuel gas combustion devices
	40 CFR Part 60, Subpart QQQ, 60.692-5, 60.695, 60.696(b)-(c), and 60.698(b)(2) and (d), as adopted by reference in Colorado Regulation No. 6, Part A	Unit does not include any control devices to comply with Subpart QQQ
	40 CFR Part 60, Subpart QQQ, 60.697(f)(3), as adopted by reference in Colorado Regulation No. 6, Part A	Unit does not use a closed drain nor closed vent system to comply with Subpart QQQ
	Colorado Regulation No. 7, VIII.A.2.a(iii) and VIII.B.6	Unit does not include add-on control equipment to comply with Regulation No. 7
	40 CFR Part 63, Subpart CC, 63.646, as adopted by reference in Colorado Regulation No. 8, Part A	Only pressure tanks are associated with this unit, and pressure tanks are exempt from these requirements

Emission Unit Description & Number	Applicable Requirement	Justification
Wastewater Treatment System	40 CFR Part 63, Subpart CC, 63.648, as adopted by reference in Colorado Regulation No. 8, Part A	This unit does not have equipment leaks as defined in 60.641 or any fluid with a HAP content greater than 5% wt.
	40 CFR Part 60, Subpart QQQ, 60.692-3, as adopted by reference in Colorado Regulation No. 6, Part A	As described in 60.692-3(d), TK-20 is subject to the requirements of 40 CFR Part 60, Subpart Kb and is not subject to the requirements of 60.692-3.
B009 – Black Oil Heater	Colorado Regulation No. 6, Part B, II.D.1, 2, and 3	Not a coal or oil fired operation. Not a combustion turbine
	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A (for fuel gas)	Fuel gas system constructed after January 4, 1983
	40 CFR Part 60, Subpart J, 60.105(a), as adopted by reference in Colorado Regulation No. 6, Part A (Pilot Gas)	Hydrogen used as pilot gas. EPA exempts refinery pilot gas from monitoring requirements when hydrogen is used as a fuel.
Group B Tanks – Grandfathered Internal Floating Roof	40 CFR Part 60, Subparts K, Ka, and Kb, as adopted by reference in Colorado Regulation No. 6, Part A	Constructed prior to 1970.
	Colorado Regulation No. 7, IV.A	Vapor pressure of VOCs is less than 11.0 psia (570 torr) at 20C.
	Colorado Regulation No. 7, VI.B2.c	Not equipped with external floating roof
	Colorado Regulation No. 7, VI.B.3.a-h	All tanks are greater than 40,000 gallons and do not require transfer from delivery vessels
	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	Tanks not included in the definition of "process unit" to which this regulation applies.
Group C Tanks – Grandfathered, Floating Roof Exempted Materials	40 CFR Part 60, Subparts K, Ka, and Kb, as adopted by reference in Colorado Regulation No. 6, Part A	Grandfathered from this regulation – all modifications have resulted in decreased emissions
	Colorado Regulation No. 7, IV.A	Vapor pressure of VOCs is less than 11.0 psia (570 torr) at 20C
	Colorado Regulation No. 7, VI.A.1	Exempted material stored in these tanks
	Colorado Regulation No. 7, VI.B.2.a(i)	Exempted material stored in these tanks
	Colorado Regulation No. 7, VI.B.3.a-i	All tanks listed are greater than 40,000 gallons
	Colorado Regulation No. 7, VII.A.1	No crude stored in listed tanks
Group D Tanks – Grandfathered, Floating Roof Vapor Pressure <0.65 psia	40 CFR Part 60, Subparts K, Ka, and Kb, as adopted by reference in Colorado Regulation No. 6, Part A	Tanks are grandfathered from these subparts.
	Colorado Regulation No. 7, IV.A	Vapor pressure of VOCs is less than 11.0 psia (570 torr) at 20C
	Colorado Regulation No. 7, VI.A.1	Exempted material stored in these tanks
	Colorado Regulation No. 7, VI.B.2.a(i.)	<0.65 psia vapor pressure at 20C
	Colorado Regulation No. 7, VI.B.3.a-i	All tanks listed are greater than 40,000 gallons

Emission Unit Description & Number	Applicable Requirement	Justification
Group D Tanks – Grandfathered, Floating Roof Vapor Pressure <0.65 psia	Colorado Regulation No. 7, VII.A.1	No crude oil stored in listed tanks
	40 CFR Part 60, Subpart UU, as adopted by reference in Colorado Regulation No. 6, Part A	Tanks constructed prior to 1980
	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	Tanks not included in definition of “process unit” to which this regulation applies
Group E Tanks		
T006	40 CFR Part 60, Subpart Kb, 60.112b(a)(2) and (3), 60.113b(b), and 60.113b(c), as adopted by reference in Colorado Regulation No. 6, Part A	Tank is equipped with an internal floating roof instead.
T006	40 CFR Part 60, Subpart Kb, 60.116b(d), as adopted by reference in Colorado Regulation No. 6, Part A	Vapor pressure of stored material is greater than 0.75 psia
T006, T020, T028, T053, T062	Colorado Regulation No. 7, VI.B.2.c	Not external floating roof tanks
T006	Colorado Regulation No. 7, VII.A.2	Not used to store crude oil and condensate prior to lease custody transfer
T006, T020, T026, T046, T047, T053, T062	40 CFR Part 63, Subpart CC, 63.646, as adopted by reference in Colorado Regulation No. 8, Part E	An existing tank subject to the requirements of 40 CFR Part 60, Subpart Kb is exempt from Subpart CC, except as provided in 63.630(n)(8)
T006, T012, T020, T026, T028, T038, T046, T047, T053, T062	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	Tanks not include in the definition of “process unit” to which this regulation applies.
T006, T012, T020, T026, T028, T038, T046, T047, T053, T062	Colorado Regulation No. 7, VI.B.3.a-i.	Tanks are greater than 40,000 gallons
T012, T028, T038	40 CFR Part 60, Subparts K, Ka, and Kb, as adopted by reference in Colorado Regulation No. 6, Part A	T012 constructed in 1953 and is grandfathered. T028 constructed before 1978. T038 constructed before February 1972.
T012, T020, T026, T028, T038, T046, T047, T053, T062	Colorado Regulation No. 7, IV.A	True vapor pressure is less than 11 psia at 20C

Emission Unit Description & Number	Applicable Requirement	Justification
T012, T026, T038	Colorado Regulation No. 7, VI.B.2.a	Not internal floating roof tanks
T012, T028, T046, T047, T053, T062	Colorado Regulation No. 7, VII.A.1	Tanks do not store crude oil
T012	Colorado Regulation No. 7, VI.B.2.c(ii)(C)	Tank 12 does not receive petroleum liquid with a true vapor pressure of 1.0 psia or greater
T026, T046, T053, T062	40 CFR Part 60, Subparts K and Ka, as adopted by reference in Colorado Regulation No. 6, Part A	T026 constructed prior to 1970. T034 constructed in 2000. T046 was built in 1999. T053 is subject to Subpart Kb instead. T062 constructed in 1993.
T046	40 CFR Part 60, Subpart Kb, except for 60.115b and 60.116b(b), as adopted by reference in Colorado Regulation No. 6, Part A	Vapor pressure below threshold of <0.5 psia
T046	Colorado Regulation No. 7, VI.B.2.a(i)	<0.65 psia vapor pressure at 20C
T047, T053	40 CFR Part 60, Subpart Kb, 60.116b(b), as adopted by reference in Colorado Regulation No. 6, Part A	Tank 47 and 53 capacity is greater than 40,000 gallons and true vapor pressure is greater than 0.75 psia
T047, T053	40 CFR Part 60, Subpart Kb, 60.112b(a)(3), 60.113b(a), 60.113b(c), 60.115b(a) and 60.115b(c)	Tanks 47 and 53 are equipped with an external floating roof as allowed by the alternative equipment specifications in 60.112b(a)
Group F Tanks	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	Tanks not include in the definition of “process unit” to which this regulation applies.
	40 CFR Part 60, Subparts K, Ka, and Kb, as adopted by reference in Colorado Regulation No. 6, Part A	Constructed prior to February 1972
	Colorado Regulation No. 7, IV.A	Material stored in tanks is not a highly volatile organic compound
	Colorado Regulation No. 6, VI.B.2.a(i.)	External floating roof tanks
	Colorado Regulation No. 7, VI.B.3.a-i	All tanks listed are greater than 40,000 gallons
	Colorado Regulation No. 7, VII	Tanks listed are not used to store crude oil
Group G Tanks	40 CFR Part 60, Subpart GGG, as adopted by reference in Colorado Regulation No. 6, Part A	Tanks not include in the definition of “process unit” to which this regulation applies.
	40 CFR Part 60, Subparts K, Ka, and Kb, as adopted by reference in Colorado Regulation No. 6, Part A	Constructed prior to February 1972
	Colorado Regulation No. 7, IV.A	Material stored in tanks is not a highly volatile organic compound
	Colorado Regulation No. 7, VI.B.2.c	Tanks listed are not external floating roof tanks
	Colorado Regulation No. 7, VII.A.1	Tanks listed are not used for crude oil
	Colorado Regulation No. 7, VI.B.3.a-i	Tanks listed are greater than 40,000 gallons and do not receive transfer from delivery vessels

2. General Conditions

Compliance with this Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the permit and other requirements specifically identified in the permit as not applicable to the source. This permit shield shall not alter or affect the following:

2.1 The provisions of §§ 25-7-112 and 25-7-113, C.R.S., or § 303 of the federal act, concerning enforcement in cases of emergency;

2.2 The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

2.3 The applicable requirements of the federal Acid Rain Program, consistent with § 408(a) of the federal act;

2.4 The ability of the Air Pollution Control Division to obtain information from a source pursuant to § 25-7-111(2)(I), C.R.S., or the ability of the Administrator to obtain information pursuant to § 114 of the federal act;

2.5 The ability of the Air Pollution Control Division to reopen the Operating Permit for cause pursuant to Regulation No. 3, Part C, § XIII.

2.6 Sources are not shielded from terms and conditions that become applicable to the source subsequent to permit issuance.

3. Streamlined Conditions

The following applicable requirements have been subsumed within this operating permit using the pertinent streamlining procedures approved by the U.S. EPA. For purposes of the permit shield, compliance with the listed permit conditions will serve as a compliance determination for purposes of the associated subsumed requirements.

Permit Condition	Streamlined (Subsumed) Requirements
Section II, Condition 22.2	Colorado Regulation No. 1, VI.A.3.e – (short term limit only) [SO_2 emissions shall not exceed 0.7 lb/bbl/day – **State-only** requirement]
Section II, Condition 5.7	EPA PSD permit, Condition 2(a), monitoring provisions only [grab samples].
Section II, Condition 5.9	EPA PSD permit, Condition 4(a), last sentence only [calculating SO_2 emissions from the Claus Plant when the CEMS in not operating].
Section II, Conditions 22.4 and 22.5.2 and Appendix H	EPA PSD permit, Condition 4(b). [calculating SO_2 emissions from other locations within the refinery on a daily basis from grab samples]
Section IV, Conditions 22.b and c	EPA PSD permit, Condition 4(c) [record retention]
Section II, Condition 2.9	EPA PSD permit, Condition 4(d) [installing a CEMS on the FCCU if capacity is increased above 8,500 bpd]

Permit Condition	Streamlined (Subsumed) Requirements
Section II, Conditions 22.4 and 22.5.2 and Appendix H	EPA PSD permit, Condition 4(e) [additional sampling when the Claus Plant is not operating for sulfur balance]
Section II, Condition 22.4 and Appendix H	EPA PSD permit Appendix A [Procedure to Determine the Sulfur Dioxide Emissions from the Refinery]

SECTION IV - General Permit Conditions

1. Administrative Changes

Regulation No. 3, 5 CCR 1001-5, Part A, § III.

The permittee shall submit an application for an administrative permit amendment to the Division for those permit changes that are described in Regulation No. 3, Part A, § I.B.1. The permittee may immediately make the change upon submission of the application to the Division.

2. Certification Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.9., V.C.16.a. & e. and V.C.17.

a. Any application, report, document and compliance certification submitted to the Air Pollution Control Division pursuant to Regulation No. 3 or the Operating Permit shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

b. All compliance certifications for terms and conditions in the Operating Permit shall be submitted to the Air Pollution Control Division at least annually unless a more frequent period is specified in the applicable requirement or by the Division in the Operating Permit.

c. Compliance certifications shall contain:

(i) the identification of each permit term and condition that is the basis of the certification;

(ii) the compliance status of the source;

(iii) whether compliance was continuous or intermittent;

(iv) the method(s) used for determining the compliance status of the source, currently and over the reporting period; and

(v) such other facts as the Air Pollution Control Division may require to determine the compliance status of the source.

d. All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

e. If the permittee is required to develop and register a risk management plan pursuant to § 112(r) of the federal act, the permittee shall certify its compliance with that requirement; the Operating Permit shall not incorporate the contents of the risk management plan as a permit term or condition.

3. Common Provisions

Common Provisions Regulation, 5 CCR 1001-2 §§ II.A., II.B., II.C., II,.E., II.F., II.I, and II.J

a. To Control Emissions Leaving Colorado

When emissions generated from sources in Colorado cross the State boundary line, such emissions shall not cause the air quality standards of the receiving State to be exceeded, provided reciprocal action is taken by the receiving State.

b. Emission Monitoring Requirements

The Division may require owners or operators of stationary air pollution sources to install, maintain, and use instrumentation to monitor and record emission data as a basis for periodic reports to the Division.

c. Performance Testing

The owner or operator of any air pollution source shall, upon request of the Division, conduct performance test(s) and furnish the Division a written report of the results of such test(s) in order to determine compliance with applicable emission control regulations. Performance test(s) shall be conducted and the data reduced in accordance with the applicable reference test methods unless the Division:

(i) specifies or approves, in specific cases, the use of a test method with minor changes in methodology;

(ii) approves the use of an equivalent method;

(iii) approves the use of an alternative method the results of which the Division has determined to be adequate for indicating where a specific source is in compliance; or

(iv) waives the requirement for performance test(s) because the owner or operator of a source has demonstrated by other means to the Division's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Commission's or Division's authority to require testing under the Colorado Revised Statutes, Title 25, Article 7 1973, and pursuant to regulations promulgated by the Commission.

Compliance test(s) shall be conducted under such conditions as the Division shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Division such records as may be necessary to determine the conditions of the performance test(s). Operations during period of startup, shutdown, and malfunction shall not constitute representative conditions of performance test(s) unless otherwise specified in the applicable standard.

The owner or operator of an affected facility shall provide the Division thirty days prior notice of the performance test to afford the Division the opportunity to have an observer present. The Division may waive the thirty day notice requirement provided that arrangements satisfactory to the Division are made for earlier testing.

The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(i) Sampling ports adequate for test methods applicable to such facility,

(ii) Safe sampling platform(s),

(iii) Safe access to sampling platform(s).

(iv) Utilities for sampling and testing equipment.

Each performance test shall consist of at least three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard the arithmetic mean of results of at least three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the owner or operator's control, compliance may, upon the Division's approval, be determined using the arithmetic mean of the results of the two other runs.

Nothing in this section shall abrogate the Division's authority to conduct its own performance test(s) if so warranted.

d. Affirmative Defense Provision for Excess Emissions during Malfunctions

Note that until such time as the U.S. EPA approves this provision into the Colorado State Implementation Plan (SIP), it shall be enforceable only by the State.

An affirmative defense to a claim of violation under these regulations is provided to owners and operators for civil penalty actions for excess emissions during periods of malfunction. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of evidence that:

(i) The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the reasonable control of the owner or operator;

(ii) The excess emissions did not stem from any activity or event that could have reasonably been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;

(iii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded;

(iv) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(v) All reasonably possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator’s actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence;

(viii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(ix) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This section is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement; and

(x) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in the Commissions’ Regulations that could be attributed to the emitting source.

The owner or operator of the facility experiencing excess emissions during a malfunction shall notify the division verbally as soon as possible, but no later than noon of the Division’s next working day, and shall submit written notification following the initial occurrence of the excess emissions by the end of the source’s next reporting period. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to failures to meet federally promulgated performance standards or emission limits, including, but not limited to, new source performance standards and national emission standards for hazardous air pollutants. The affirmative defense provision does not apply to state implementation plan (sip) limits or permit limits that have been set taking into account potential emissions during malfunctions, including, but not necessarily limited to, certain limits with 30-day or longer averaging times, limits that indicate they apply during malfunctions, and limits that indicate they apply at all times or without exception.

e. Circumvention Clause

A person shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of air pollutants to the atmosphere, reduces or conceals an emission which would otherwise constitute a violation of this regulation. No person shall circumvent this regulation by using more openings than is considered normal practice by the industry or activity in question.

f. Compliance Certifications

For the purpose of submitting compliance certifications or establishing whether a person has violated or is in violation of any standard in the Colorado State Implementation Plan, nothing in the Colorado State Implementation Plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. Evidence that has the effect of making any relevant standard or permit term more stringent shall not be credible for proving a violation of the standard or permit term.

When compliance or non-compliance is demonstrated by a test or procedure provided by permit or other applicable requirement, the owner or operator shall be presumed to be in compliance or non-compliance unless other relevant credible evidence overcomes that presumption.

g. Affirmative Defense Provision for Excess Emissions During Startup and Shutdown

An affirmative defense is provided to owners and operators for civil penalty actions for excess emissions during periods of startup and shutdown. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of the evidence that:

(i) The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

(ii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;

(iii) If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(iv) The frequency and duration of operation in startup and shutdown periods were minimized to the maximum extent practicable;

(v) All possible steps were taken to minimize the impact of excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator’s actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence; and,

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This subparagraph is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement.

The owner or operator of the facility experiencing excess emissions during startup and shutdown shall notify the Division verbally as soon as possible, but no later than two (2) hours after the start of the next working day, and shall submit written quarterly notification following the initial occurrence of the excess emissions. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to State Implementation Plan provisions or other requirements that derive from new source performance standards (NSPS) or national emissions standards for hazardous air pollutants (NESHAPS), any other federally enforceable performance standard or emission limit with an averaging time greater than twenty-four hours. In addition, an affirmative defense cannot be used by a single source or small group of sources where the excess emissions have the potential to cause an exceedance of the ambient air quality standards or Prevention of Significant Deterioration (PSD) increments.

In making any determination whether a source established an affirmative defense, the Division shall consider the information within the notification required above and any other information the Division deems necessary, which may include, but is not limited to, physical inspection of the facility and review of documentation pertaining to the maintenance and operation of process and air pollution control equipment.

4. Compliance Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.C.9., V.C.11. & 16.d. and § 25-7-122.1(2), C.R.S.

a. The permittee must comply with all conditions of the Operating Permit. Any permit noncompliance relating to federally-enforceable terms or conditions constitutes a violation of the federal act, as well as the state act and Regulation No. 3. Any permit noncompliance relating to state-only terms or conditions constitutes a violation of the state act and Regulation No. 3, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under § 304 of the federal act. Any such violation of the federal act, the state act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in §§ X. and XI. of Regulation No. 3, Part C.

d. The permittee shall furnish to the Air Pollution Control Division, within a reasonable time as specified by the Division, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim.

e. Any schedule for compliance for applicable requirements with which the source is not in compliance at the time of permit issuance shall be supplemental, and shall not sanction noncompliance with, the applicable requirements on which it is based.

f. For any compliance schedule for applicable requirements with which the source is not in compliance at the time of permit issuance, the permittee shall submit, at least every 6 months unless a more frequent period is specified in the applicable requirement or by the Air Pollution Control Division, progress reports which contain the following:

  (i) dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

  (ii) an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

g. The permittee shall not knowingly falsify, tamper with, or render inaccurate any monitoring device or method required to be maintained or followed under the terms and conditions of the Operating Permit.

5. Emergency Provisions

Regulation No. 3, 5 CCR 1001-5, Part C, § VII.

An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed the technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. "Emergency" does not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error. An emergency constitutes an affirmative defense to an enforcement action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates, through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. an emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. the permitted facility was at the time being properly operated;

c. during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. the permittee submitted oral notice of the emergency to the Air Pollution Control Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emissions limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

This emergency provision is in addition to any emergency or malfunction provision contained in any applicable requirement.

6. Emission Standards for Asbestos

Regulation No. 8, 5 CCR 1001-10, Part B

The permittee shall not conduct any asbestos abatement activities except in accordance with the provisions of Regulation No. 8, Part B, "emission standards for asbestos."

7. Emissions Trading, Marketable Permits, Economic Incentives

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.13.

No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are specifically provided for in the permit.

8. Fee Payment

CRS 25-7-114.1(6) and 25-7-114.7

a. The permittee shall pay an annual emissions fee in accordance with the provisions of CRS 25-7-114.7. A 1% per month late payment fee shall be assessed against any invoice amounts not paid in full on the 91st day after the date of invoice, unless a permittee has filed a timely protest to the invoice amount.

b. The permittee shall pay a permit processing fee in accordance with the provisions of CRS 45-7-114.7. If the Division estimates that processing of the permit will take more than 30 hours, it will notify the permittee of its estimate of what the actual charges may be prior to commencing any work exceeding the 30 hour limit.

c. The permittee shall pay an APEN fee in accordance with the provisions of 25-7-114.1(6) for each APEN or revised APEN filed.

9. Fugitive Particulate Emissions

Regulation No. 1, 5 CCR 1001-3, § III.D.1.

The permittee shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere, in accordance with the provisions of Regulation No. 1, § III.D.1.

10. Inspection and Entry

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.16.b.

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Air Pollution Control Division, or any authorized representative, to perform the following:

a. enter upon the permittee's premises where an Operating Permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

b. have access to, and copy, at reasonable times, any records that must be kept under the conditions of the permit;

c. inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the Operating Permit;

d. sample or monitor at reasonable times, for the purposes of assuring compliance with the Operating Permit or applicable requirements, any substances or parameters.

11. Minor Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, §§ X. & XI.

The permittee shall submit an application for a minor permit modification before making the change requested in the application. The permit shield shall not extend to minor permit modifications.

12. New Source Review

Regulation No. 3, 5 CCR 1001-5, Part B

The permittee shall not commence construction or modification of a source required to be reviewed under the New Source Review provisions of Regulation No. 3, Part B, without first receiving a construction permit.

13. No Property Rights Conveyed

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.11.d.

This permit does not convey any property rights of any sort, or any exclusive privilege.

14. Odor

Regulation No. 2, 5 CCR 1001-4, Part A

As a matter of state law only, the permittee shall comply with the provisions of Regulation No. 2 concerning odorous emissions.

15. Off-Permit Changes to the Source

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.B.

The permittee shall record any off-permit change to the source that causes the emissions of a regulated pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from the change, including any other data necessary to show compliance with applicable ambient air quality standards. The permittee shall provide contemporaneous notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permit shield shall not apply to any off-permit change.

16. Opacity

Regulation No. 1, 5 CCR 1001-3, §§ I., II.

The permittee shall comply with the opacity emissions limitation set forth in Regulation No. 1, §§ I.-II.

17. Open Burning

Regulation No. 9, 5 CCR 1001-11

The permittee shall obtain a permit from the Division for any regulated open burning activities in accordance with provisions of Regulation No. 9.

18. Ozone Depleting Compounds

Regulation No. 15, 5 CCR 1001-17

The permittee shall comply with the provisions of Regulation No. 15 concerning emissions of ozone depleting compounds. Sections I., II.C., II.D., III., IV., and V. of Regulation No. 15 shall be enforced as a matter of state law only.

19. Permit Expiration and Renewal

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.6., IV.C., V.C.2.

a. The permit term shall be five (5) years. The permit shall expire at the end of its term. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted.

b. Applications for renewal shall be submitted at least twelve months, but not more than 18 months, prior to the expiration of the Operating Permit. An application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application.

20. Portable Sources

Regulation No. 3, 5 CCR 1001-5, Part C, § II.D.

Portable Source permittees shall notify the Air Pollution Control Division at least 10 days in advance of each change in location.

21. Prompt Deviation Reporting

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.7.b.

The permittee shall promptly report any deviation from permit requirements, including those attributable to malfunction conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken.

"Prompt" is defined as follows:

a. Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit; or

b. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

(i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report shall be made within 24 hours of the occurrence;

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report shall be made within 48 hours; and

(iii) For all other deviations from permit requirements, the report shall be submitted every six (6) months, except as otherwise specified by the Division in the permit in accordance with paragraph 22.d. below.

c. If any of the conditions in paragraphs b.i or b.ii above are met, the source shall notify the Division by telephone (303-692-3155) or facsimile (303-782-0278) based on the timetables listed above. *[Explanatory note: Notification by telephone or* facsimile *must specify that this notification is a deviation report for an Operating Permit.]* A written notice, certified consistent with General Condition 2.a. above (Certification Requirements), shall be submitted within 10 working days of the occurrence. All deviations reported under this section shall also be identified in the 6-month report required above.

"Prompt reporting" does not constitute an exception to the requirements of "Emergency Provisions" for the purpose of avoiding enforcement actions.

22. Record Keeping and Reporting Requirements

Regulation No. 3, 5 CCR 1001-5, Part A, § II.; Part C, §§ V.C.6., V.C.7.

a. Unless otherwise provided in the source specific conditions of this Operating Permit, the permittee shall maintain compliance monitoring records that include the following information:

(i) date, place as defined in the Operating Permit, and time of sampling or measurements;

(ii) date(s) on which analyses were performed;

(iii) the company or entity that performed the analysis;

(iv) the analytical techniques or methods used;

(v) the results of such analysis; and

(vi) the operating conditions at the time of sampling or measurement.

b. The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the Operating Permit. With prior approval of the Air Pollution Control Division, the permittee may maintain any of the above records in a computerized form.

c. Permittees must retain records of all required monitoring data and support information for the most recent twelve (12) month period, as well as compliance certifications for the past five (5) years on-site at all times. A permittee shall make available for the Air Pollution Control Division's review all other records of required monitoring data and support information required to be retained by the permittee upon 48 hours advance notice by the Division.

d. The permittee shall submit to the Air Pollution Control Division all reports of any required monitoring at least every six (6) months, unless an applicable requirement, the compliance assurance monitoring rule, or the Division requires submission on a more frequent basis. All instances of deviations from any permit requirements must be clearly identified in such reports.

e. The permittee shall file an Air Pollutant Emissions Notice ("APEN") prior to constructing, modifying, or altering any facility, process, activity which constitutes a stationary source from which air pollutants are or are to be emitted, unless such source is exempt from the APEN filing requirements of Regulation No. 3, Part A, § II.D. A revised APEN shall be filed annually whenever a significant change in emissions, as defined in Regulation No. 3, Part A, § II.C.2., occurs; whenever there is a change in owner or operator of any facility, process, or activity; whenever new control equipment is installed; whenever a different type of control equipment replaces an existing type of control equipment; whenever a permit limitation must be modified; or before the APEN expires. An APEN is valid for a period of five years. The five-year period recommences when a revised APEN is received by the Air Pollution Control Division. Revised APENs shall be submitted no later than 30 days before the five-year term expires. Permittees submitting revised APENs to inform the Division of a change in actual emission rates must do so by April 30 of the following year. Where a permit revision is required, the revised APEN must be filed along with a request for permit revision. APENs for changes in control equipment must be submitted before the change occurs. Annual fees are based on the most recent APEN on file with the Division.

23. Reopenings for Cause

Regulation No. 3, 5 CCR 1001-5, Part C, § XIII.

a. The Air Pollution Control Division shall reopen, revise, and reissue Operating Permits; permit reopenings and reissuance shall be processed using the procedures set forth in Regulation No. 3, Part C, § III., except that proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists.

b. The Division shall reopen a permit whenever additional applicable requirements become applicable to a major source with a remaining permit term of three or more years, unless the effective date of the requirements is later than the date on which the permit expires, or unless a general permit is obtained to address the new requirements; whenever additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program; whenever the Division determines the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or whenever the Division determines that the permit must be revised or revoked to assure compliance with an applicable requirement.

c. The Division shall provide 30 days' advance notice to the permittee of its intent to reopen the permit, except that a shorter notice may be provided in the case of an emergency.

d. The permit shield shall extend to those parts of the permit that have been changed pursuant to the reopening and reissuance procedure.

24. Section 502(b)(10) Changes

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.A.

The permittee shall provide a minimum 7-day advance notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permittee shall attach a copy of each such notice given to its Operating Permit.

25. Severability Clause

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.10.

In the event of a challenge to any portion of the permit, all emissions limits, specific and general conditions, monitoring, record keeping and reporting requirements of the permit, except those being challenged, remain valid and enforceable.

26. Significant Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, § III.B.2.

The permittee shall not make a significant modification required to be reviewed under Regulation No. 3, Part B ("Construction Permit" requirements) without first receiving a construction permit. The permittee shall submit a complete Operating Permit application or application for an Operating Permit revision for any new or modified source within twelve months of commencing operation, to the address listed in Item 1 in Appendix D of this permit. If the permittee chooses to use the "Combined Construction/Operating Permit" application procedures of Regulation No. 3, Part C, then the Operating Permit must be received prior to commencing construction of the new or modified source.

27. Special Provisions Concerning the Acid Rain Program

Regulation No. 3, 5 CCR 1001-5, Part C, §§ V.C.1.b. & 8

a. Where an applicable requirement of the federal act is more stringent than an applicable requirement of regulations promulgated under Title IV of the federal act, 40 Code of Federal Regulations (CFR) Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable.

b. Emissions exceeding any allowances that the source lawfully holds under Title IV of the federal act or the regulations promulgated thereunder, 40 CFR Part 72, are expressly prohibited.

28. Transfer or Assignment of Ownership

Regulation No. 3, 5 CCR 1001-5, Part C, § II.C.

No transfer or assignment of ownership of the Operating Permit source will be effective unless the prospective owner or operator applies to the Air Pollution Control Division on Division-supplied Administrative Permit Amendment forms, for reissuance of the existing Operating Permit. No administrative permit shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the permittee and the prospective owner or operator has been submitted to the Division.

29. Volatile Organic Compounds

Regulation No. 7, 5 CCR 1001-9, §§ III & V.

a. For sources located in an ozone non-attainment area or the Denver Metro Attainment Maintenance Area, all storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g., maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing shall be conducted as in Regulation No. 7, Section VIII.C.3.

Except when otherwise provided by Regulation No. 7, all volatile organic compounds, excluding petroleum liquids, transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

b. The permittee shall not dispose of volatile organic compounds by evaporation or spillage unless Reasonably Available Control Technology (RACT) is utilized.

c. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Colorado Regulation No. 7, Section VI, shall permit gasoline to be intentionally spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

30. Wood Stoves and Wood burning Appliances

Regulation No. 4, 5 CCR 1001-6

The permittee shall comply with the provisions of Regulation No. 4 concerning the advertisement, sale, installation, and use of wood stoves and wood burning appliances.

OPERATING PERMIT APPENDICES

A - INSPECTION INFORMATION
B - MONITORING AND PERMIT DEVIATION REPORT
C - COMPLIANCE CERTIFICATION REPORT
D - NOTIFICATION ADDRESSES
E - PERMIT ACRONYMS
F - PERMIT MODIFICATIONS
G- (RESERVED)
H - SO_2 EMISSIONS CALCULATION METHODOLOGY

*DISCLAIMER:

None of the information found in these Appendices shall be considered to be State or Federally enforceable, except as otherwise stated in this permit, and is presented to assist the source, permitting authority, inspectors, and citizens.

APPENDIX A - Inspection Information

Directions to Plant:

The facility is located at 5800 Brighton Boulevard, Commerce City. Exist I-70 at Brighton Boulevard. Go north on Brighton Boulevard. Refinery is on the east side of Brighton Boulevard just prior to reaching I-270. The Suncor visitor orientation facility is located on 56^{th} Avenue near the Sour Crude Unit entrance.

Safety Equipment Required:

Eye Protection; Hard Hat; Safety Shoes; Hearing Protection

Facility Plot Plan:

A facility plot plan is not included in the permit at this time.

List of Insignificant Activities:

The following list of insignificant activities was provided by the source to assist in the understanding of the facility layout. Since there is no requirement to update such a list, activities may have changed since the last filing.

Insignificant activities and/or sources of emissions as submitted in the application are as follows:

Noncommercial (in-house) experimental and analytical laboratory equipment which is bench scale in nature including quality control/quality assurance laboratories, process support laboratories, environmental laboratories supporting a manufacturing or industrial facility, and research and development laboratories.

Research and development activities that which are of a small pilot scale and which process less than 10,000 pounds of test material per year.

Small pilot scale research and development projects less than six months in duration with controlled actual emissions less than 500 pounds of any criteria pollutant or 10 pounds of any non-criteria reportable pollutant.

Disturbance of surface areas for purposes of land development, which do not exceed 25 contiguous acres and which do not exceed six months in duration. (This does not include mining operations or disturbance of contaminated soil.)

Each individual piece of fuel burning equipment, other than smokehouse generators and internal combustion engines, which uses gaseous fuel, and which has a design ate less than or equal to 5 million Btu per hour. (See definition of fuel burning equipment, Common Provisions Regulation.)

Chemical storage tanks or containers that hold less than 500 gallons, and which have a daily throughput less than 25 gallons.

Landscaping and site housekeeping devices equal to or less than 10 H.P. in size (lawnmowers, trimmers, snow blowers, etc.).

Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed 5,000 gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers.

Storage of butane, propane, or liquefied petroleum gas in a vessel with a capacity of less than 60,000 gallons, provided the requirements of Regulation No. 7, Section IV are met, where applicable.

Fuel storage and dispensing equipment in ozone attainment areas operated solely for company-owned vehicles where the daily fuel throughput is no more than 400 gallons per day, averaged over a 30 day period.

Storage tanks meeting all of the following criteria:

(I) annual throughput is less than 400,000 gallons; and

(II) the liquid stored is one of the following:

(A) diesel fuels 1-D, 2-D, or 4-D;

(B) fuel oils #1 through #6;

(C) Gas turbine fuels 1-GT through 4-GT;

(D) an oil/water mixture with a vapor pressure lower than that of diesel fuel (Reid vapor pressure of .025 PSIA).

Each individual piece of fuel burning equipment which uses gaseous fuel, and which has a design rate less than or equal to 10 million Btu per hour, and which is used solely for heating buildings for personal comfort.

Stationary Internal Combustion Engines which:

(I) power portable drilling rigs; or

(II) are emergency power generators which have a rated horsepower of less than 260; or operate no more than 250 hours per year and have a rated horsepower of less than 737; or operate no more than 100 hours per year and have a rated horsepower of less than 1840; or

(III) have actual emissions less than five tons per year or rated horsepower of less than 50.

Air pollution emission units, operations or activities with emissions less than the appropriate de minimis reporting level.

Specific equipment identified in the application:

Diesel Fuel Sulfur Analyzer Maintenance
Coalescer Drains
Kerosene
Diesel

Water Drains
- Stabilizer Overhead
- Desulfurizer Overhead Drum
- FCC MC Receiver
- FCC Gas Compressor
- Stabilizer
- Recycle
- FF Drum
- Splitter
- Depropanizer
- Deethanizer
- Deisobutanizer

Filter Changeovers/Cleaning
- Gland Oil Filters
- Naphtha Filters
- Diesel Filters
- Kerosene Filters

Regeneration Scrubber Water
Moisture Analyzer Vent
MT Bottoms Pump Strainer Maintenance
Sweet FG Drum Water Boot Drain
Sulfur Pit (Tank 89)
Sulfur Seal Leg Unplugging Acts
CEM Analyzer Vents
CEM Maintenance
Spent Caustic Storage
Neutralized Caustic Drain
Decarborator
Deaerator
Sumps
Refinery Flare Knockout Pot
Refinery Flare Seal Drain
Sample Handling/Disposal
Octane Engines
Maintenance Activities
- Spray Painting
- Solids Handling
- Fin-Fan Cleaning
- Equipment Maintenance
- Exchanger Cleaning
- Vessel Cleaning
- Parts Cleaning (3 degreasers)
- Metal Working
- Welding, cutting, grinding

- Vehicle Maintenance

Waste Activities

- Drum Storage
- Rolloffs
- Sampling

Lubrimist System
Seal Oil Reservoir
Lube Oil Reservoir Vents
Firefighting Training
Lube Oil Storage
Chemical/Catalyst Storage
Diesel Vehicle Refueling
Tank T003
Tank T019
Tank T013
Tank T014
Tank T015
Tank T029
Tank T032
GW Remediation
Laboratory Vents
Building air conditioning systems
Minor Maintenance Work: Insulating, Welding, Soil Cleanup.

APPENDIX B

Reporting Requirements and Definitions

with codes ver 2/20/07

Please note that, pursuant to 113(c)(2) of the federal Clean Air Act, any person who knowingly:

(A) makes any false material statement, representation, or certification in, or omits material information from, or knowingly alters, conceals, or fails to file or maintain any notice, application, record, report, plan, or other document required pursuant to the Act to be either filed or maintained (whether with respect to the requirements imposed by the Administrator or by a State);

(B) fails to notify or report as required under the Act; or

(C) falsifies, tampers with, renders inaccurate, or fails to install any monitoring device or method required to be maintained or followed under the Act shall, upon conviction, be punished by a fine pursuant to title 18 of the United States Code, or by imprisonment for not more than 2 years, or both. If a conviction of any person under this paragraph is for a violation committed after a first conviction of such person under this paragraph, the maximum punishment shall be doubled with respect to both the fine and imprisonment.

The permittee must comply with all conditions of this operating permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

The Part 70 Operating Permit program requires three types of reports to be filed for all permits.
All required reports must be certified by a responsible official.

Report #1: Monitoring Deviation Report (due at least every six months)

For purposes of this operating permit, the Division is requiring that the monitoring reports are due every six months unless otherwise noted in the permit. All instances of deviations from permit monitoring requirements must be clearly identified in such reports.

For purposes of this operating permit, monitoring means any condition determined by observation, by data from any monitoring protocol, or by any other monitoring which is required by the permit as well as the recordkeeping associated with that monitoring. This would include, for example, fuel use or process rate monitoring, fuel analyses, and operational or control device parameter monitoring.

Report #2: Permit Deviation Report (must be reported "promptly")

In addition to the monitoring requirements set forth in the permits as discussed above, each and every requirement of the permit is subject to deviation reporting. The reports must address deviations from permit requirements, including those attributable to malfunctions as defined in this Appendix, the probable cause of such deviations, and any corrective actions or preventive measures taken. All deviations from any term or condition of the permit are required to be summarized or referenced in the annual compliance certification.

For purposes of this operating permit, “malfunction” shall refer to both emergency conditions and malfunctions. Additional discussion on these conditions is provided later in this Appendix.

For purposes of this operating permit, the Division is requiring that the permit deviation reports are due as set forth in General Condition 21. Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. For example, quarterly Excess Emission Reports required by an NSPS or Regulation No. 1, Section IV.

In addition to the monitoring deviations discussed above, included in the meaning of deviation for the purposes of this operating permit are any of the following:

(1) A situation where emissions exceed an emission limitation or standard contained in the permit;

(2) A situation where process or control device parameter values demonstrate that an emission limitation or standard contained in the permit has not been met;

(3) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or,

(4) A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only if the emission point is subject to CAM)

For reporting purposes, the Division has combined the Monitoring Deviation Report with the Permit Deviation Report. All deviations shall be reported using the following codes:

1 = Standard:	When the requirement is an emission limit or standard
2 = Process:	When the requirement is a production/process limit
3 = Monitor:	When the requirement is monitoring
4 = Test:	When the requirement is testing
5 = Maintenance:	When required maintenance is not performed
6 = Record:	When the requirement is recordkeeping
7 = Report:	When the requirement is reporting
8 = CAM:	A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other:	When the deviation is not covered by any of the above categories

Report #3: Compliance Certification (annually, as defined in the permit)

Submission of compliance certifications with terms and conditions in the permit, including emission limitations, standards, or work practices, is required not less than annually.

Compliance Certifications are intended to state the compliance status of each requirement of the permit over the certification period. They must be based, at a minimum, on the testing and monitoring methods specified in the permit that were conducted during the relevant time period. In addition, if the owner or operator knows of other material information (i.e. information beyond required monitoring that has been specifically assessed in relation to how the information potentially affects compliance status), that information must be identified and addressed in the compliance certification. The compliance certification must include the following:

- The identification of each term or condition of the permit that is the basis of the certification;
- Whether or not the method(s) used by the owner or operator for determining the compliance status with each permit term and condition during the certification period was the method(s) specified in the permit. Such methods and other means shall include, at a minimum, the methods and means required in the permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Clean Air Act, which prohibits knowingly making a false certification or omitting material information;
- The status of compliance with the terms and conditions of the permit, and whether compliance was continuous or intermittent. The certification shall identify each deviation and take it into account in the compliance certification. Note that not all deviations are considered violations.[1]
- Such other facts as the Division may require, consistent with the applicable requirements to which the source is subject, to determine the compliance status of the source.

The Certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only for emission points subject to CAM)

Note the requirement that the certification shall identify each deviation and take it into account in the compliance certification. Previously submitted deviation reports, including the deviation report submitted at the time of the annual certification, may be referenced in the compliance certification.

Startup, Shutdown, Malfunctions and Emergencies

Understanding the application of Startup, Shutdown, Malfunctions and Emergency Provisions, is very important in both the deviation reports and the annual compliance certifications.

Startup, Shutdown, and Malfunctions

Please note that exceedances of some New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards that occur during Startup, Shutdown or Malfunctions may not be considered to be non-compliance since emission limits or standards often do not apply unless specifically stated in the NSPS. Such exceedances must, however, be reported as excess emissions per the NSPS/MACT rules and

[1] For example, given the various emissions limitations and monitoring requirements to which a source may be subject, a deviation from one requirement may not be a deviation under another requirement which recognizes an exception and/or special circumstances relating to that same event.

would still be noted in the deviation report. In regard to compliance certifications, the permittee should be confident of the information related to those deviations when making compliance determinations since they are subject to Division review. The concepts of Startup, Shutdown and Malfunctions also exist for Best Available Control Technology (BACT) sources, but are not applied in the same fashion as for NSPS and MACT sources.

Emergency Provisions

Under the Emergency provisions of Part 70 certain operational conditions may act as an affirmative defense against enforcement action if they are properly reported.

DEFINITIONS

Malfunction (NSPS) means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Malfunction (SIP) means any sudden and unavoidable failure of air pollution control equipment or process equipment or unintended failure of a process to operate in a normal or usual manner. Failures that are primarily caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

Emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

Monitoring and Permit Deviation Report - Part I

1. Following is the **required** format for the Monitoring and Permit Deviation report to be submitted to the Division as set forth in General Condition 21. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

2. Part II of this Appendix B shows the format and information the Division will require for describing periods of monitoring and permit deviations, or malfunction or emergency conditions as indicated in the Table below. One Part II Form must be completed for each Deviation. Previously submitted reports (e.g. EER's or malfunctions) may be referenced and the form need not be filled out in its entirety.

FACILITY NAME: Suncor Energy (U.S.A), Inc. – Commerce City Refinery, Plant 2 (East)
OPERATING PERMIT NO: 95OPAD108
REPORTING PERIOD:______________ (see first page of the permit for specific reporting period and dates)

Operating Permit Unit ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction /Emergency Condition Reported During Period?	
		YES	NO		YES	NO
P001	Crude Distillation Unit					
B001	Crude Heater					
B010	Vacuum Heater					
P003	Fluid Catalytic Cracking Unit (FCCU)					
B002	Heater					
P004	Reactor-Regenerator					
P014	Catalyst Handling					
P005	Naphtha Hydrotreater Reformer					
B003	Heater #1					
B004	Heater #2					
B005	Heater #3					
F004	Reactors (Catalyst Regeneration)					
P006	Polymerization Unit					
F008	Reactor #1 (Catalyst Unloading)					
F009	Reactor #2 (Catalyst Unloading)					
P007	Gas Plant					
P009	Sulfur Recovery Plant					
P008	Amine Unit					
B006	Boiler 1					
B007	Boiler 2					
B008	Boiler 3					
P011	Cooling Tower					
F015	South Crude Unloading					
F016	North Crude Unloading					

Operating Permit Unit ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction /Emergency Condition Reported During Period?	
		YES	NO		YES	NO
F024	Truck Loading Dock					
	Refinery Flare					
F019	Railcar Dock					
F020	Truck Dock					
T050	Pressure Tank 50					
T051	Pressure Tank 51					
T060	Pressure Tank 60					
T061	Pressure Tank 61					
T063	Pressure Tank 63					
T064	Pressure Tank 64					
T066	Pressure Tank 66					
T067	Pressure Tank 67					
T068	Pressure Tank 68					
T069	Pressure Tank 69					
	Wastewater Treatment System					
F021	API Separators – Upper API					
F022	API Separators – Middle API					
F023	API Separators – Lower API					
F011	Gas Plant Sewers					
F025	Sour Water Stripper Sewers					
F027	South Crude Unloading Sewers					
B009	Black Oil Heater					
T010	Tank 10					
T011	Tank 11					
T027	Tank 27					
T030	Tank 30					
T040	Tank 40					
T041	Tank 41					
T004	Tank 4					
T005	Tank 5					
T031	Tank 31					
T039	Tank 39					
T055	Tank 55					
T056	Tank 56					
T006	Tank 6					
T012	Tank 12					
T020	Tank 20					
T026	Tank 26					
T028	Tank 28					

Operating Permit Unit ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction /Emergency Condition Reported During Period?	
		YES	NO		YES	NO
T034	Tank 34					
T038	Tank 38					
T046	Tank 46					
T047	Tank 47					
T053	Tank 53					
T062	Tank 62					
T079	Tank 79					
T035	Tank 35					
T036	Tank 36					
T044	Tank 44					
T052	Tank 52					
T054	Tank 54					
T024	Tank 24					
T025	Tank 25					
T037	Tank 37					
T058	Tank 58					
	SEP Project					
	General Conditions					
	Insignificant Activities					

[1] See previous discussion regarding what is considered to be a deviation. Determination of whether or not a deviation has occurred shall be based on a reasonable inquiry using readily available information.

[2]Use the following entries as appropriate:

1 = Standard: When the requirement is an emission limit or standard
2 = Process: When the requirement is a production/process limit
3 = Monitor: When the requirement is monitoring
4 = Test: When the requirement is testing
5 = Maintenance: When required maintenance is not performed
6 = Record: When the requirement is recordkeeping
7 = Report: When the requirement is reporting
8 = CAM: A situation in which an excursion or exceedance as defined in 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other: When the deviation is not covered by any of the above categories

Monitoring and Permit Deviation Report - Part II

FACILITY NAME: Suncor Energy (U.S.A.), Inc. – Commerce City Refinery, Plant 2 (East)
OPERATING PERMIT NO: 95OPAD108
REPORTING PERIOD:

Is the deviation being claimed as an: Emergency ______ Malfunction______ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown ______ Malfunction _____ Normal Operation ____________

OPERATING PERMIT UNIT IDENTIFICATION:

Operating Permit Condition Number Citation

Explanation of Period of Deviation

Duration (start/stop date & time)

Action Taken to Correct the Problem

Measures Taken to Prevent a Reoccurrence of the Problem

Dates of Malfunctions/Emergencies Reported (if applicable)

Deviation Code _________________ Division Code QA: ______________

SEE EXAMPLE ON THE NEXT PAGE

EXAMPLE

FACILITY NAME: Acme Corp.
OPERATING PERMIT NO: 96OPZZXXX
REPORTING PERIOD: 1/1/04 - 6/30/06

Is the deviation being claimed as an: Emergency ______ Malfunction __XX____ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown ______ Malfunction
Normal Operation ___________________

OPERATING PERMIT UNIT IDENTIFICATION:

Asphalt Plant with a Scrubber for Particulate Control - Unit XXX

<u>Operating Permit Condition Number Citation</u>

Section II, Condition 3.1 - Opacity Limitation

<u>Explanation of Period of Deviation</u>

Slurry Line Feed Plugged

<u>Duration</u>

START- 1730 4/10/06
END- 1800 4/10/06

<u>Action Taken to Correct the Problem</u>

Line Blown Out

<u>Measures Taken to Prevent Reoccurrence of the Problem</u>

Replaced Line Filter

<u>Dates of Malfunction/Emergencies Reported (if applicable)</u>

5/30/06 to A. Einstein, APCD

Deviation Code _________________ Division Code QA: _______________

Monitoring and Permit Deviation Report - Part III

REPORT CERTIFICATION

SOURCE NAME: Suncor Energy (U.S.A.), Inc. – Commerce City Refinery, Plant 2 (East)

FACILITY IDENTIFICATION NUMBER: 0010003

PERMIT NUMBER: 95OPAD108

REPORTING PERIOD:________________ (see first page of the permit for specific reporting period and dates)

All information for the Title V Semi-Annual Deviation Reports must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B.38. This signed certification document must be packaged with the documents being submitted.

STATEMENT OF COMPLETENESS

I have reviewed the information being submitted in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this submittal are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in Sub-Section 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of Sub-Section 25-7 122.1, C.R.S.

____

Printed or Typed Name — Title

____

Signature of Responsible Official — Date Signed

Note: Deviation reports shall be submitted to the Division at the address given in Appendix D of this permit. No copies need be sent to the U.S. EPA.

APPENDIX C

Required Format for Annual Compliance Certification Report

Following is the format for the Compliance Certification report to be submitted to the Division and the U.S. EPA annually based on the effective date of the permit. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

FACILITY NAME: Suncor Energy (U.S.A.), Inc. – Commerce City Refinery, Plant 2 (East)

OPERATING PERMIT NO: 95OPAD108
REPORTING PERIOD:

I. Facility Status

___ During the entire reporting period, this source was in compliance with **ALL** terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference. The method(s) used to determine compliance is/are the method(s) specified in the Permit.

___ With the possible exception of the deviations identified in the table below, this source was in compliance with all terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference, during the entire reporting period. The method used to determine compliance for each term and condition is the method specified in the Permit, unless otherwise indicated and described in the deviation report(s). Note that not all deviations are considered violations.

Operating Permit Unit ID	Unit Description	Deviations Reported [1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
P001	Crude Distillation Unit						
B001	Crude Heater						
B010	Vacuum Heater						
P003	Fluid Catalytic Cracking Unit (FCCU)						
B002	Heater						
P004	Reactor-Regenerator						
P014	Catalyst Handling						
P005	Naphtha Hydrotreater/Reformer						
B003	Heater #1						
B004	Heater #2						
B005	Heater #3						
F004	Reactors (Catalyst Regeneration)						
P006	Polymerization Unit						
F008	Reactor #1 (Catalyst Unloading)						

Operating Permit Unit ID	Unit Description	Deviations Reported [1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
F009	Reactor #2 (Catalyst Unloading)						
P009	Sulfur Recovery Plant						
P008	Amine Unit						
B006	Boiler 1						
B007	Boiler 2						
B008	Boiler 3						
P011	Cooling Tower						
F015	South Crude Unloading						
F016	North Crude Unloading						
F024	Truck Loading Dock						
	Refinery Flare						
F019	Railcar Dock						
F020	Truck Dock						
T050	Pressure Tank 50						
T051	Pressure Tank 51						
T060	Pressure Tank 60						
T061	Pressure Tank 61						
T063	Pressure Tank 63						
T064	Pressure Tank 64						
T066	Pressure Tank 66						
T067	Pressure Tank 67						
T068	Pressure Tank 68						
T069	Pressure Tank 69						
	Wastewater Treatment Plant						
F021	API Separators – Upper API						
F022	API Separators – Middle API						
F023	API Separators – Lower API						
F011	Gas Plant Sewers						
F025	Sour Water Stripper Sewers						
F027	South Crude Unloading Sewers						
B009	Black Oil Heater						
T010	Tank 10						
T011	Tank 11						
T027	Tank 27						
T030	Tank 30						
T040	Tank 40						
T041	Tank 41						
T004	Tank 4						
T005	Tank 5						

Operating Permit Unit ID	Unit Description	Deviations Reported [1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
T031	Tank 31						
T039	Tank 39						
T055	Tank 55						
T056	Tank 56						
T006	Tank 6						
T012	Tank 12						
T020	Tank 20						
T026	Tank 26						
T028	Tank 28						
T034	Tank 34						
T046	Tank 46						
T047	Tank 47						
T053	Tank 53						
T062	Tank 62						
T079	Tank 79						
T035	Tank 35						
T036	Tank 36						
T044	Tank 44						
T052	Tank 52						
T054	Tank 54						
T024	Tank 24						
T025	Tank 25						
T037	Tank 37						
T058	Tank 58						
	SEP Project						
	General Conditions						
	Insignificant Activities [4]						

[1] If deviations were noted in a previous deviation report , put an "X" under "previous". If deviations were noted in the current deviation report (i.e. for the last six months of the annual reporting period), put an "X" under "current". Mark both columns if both apply.

[2] Note whether the method(s) used to determine the compliance status with each term and condition was the method(s) specified in the permit. If it was not, mark "no" and attach additional information/explanation.

[3] Note whether the compliance status with of each term and condition provided was continuous or intermittent. "Intermittent Compliance" can mean either that noncompliance has occurred or that the owner or operator has data sufficient to certify compliance only on an intermittent basis. Certification of intermittent compliance therefore does not necessarily mean that any noncompliance has occurred.

NOTE:

The Periodic Monitoring requirements of the Operating Permit program rule are intended to provide assurance that even in the absence of a continuous system of monitoring the Title V source can demonstrate whether it has operated in continuous compliance for the duration of the reporting period. Therefore, if a source 1) conducts all of the monitoring and recordkeeping required in its permit, even if such activities are done periodically and not continuously, and if 2) such monitoring and recordkeeping does not indicate non-compliance, and if 3) the Responsible Official is not aware of any credible evidence that indicates non-compliance, then the Responsible Official can certify that the emission point(s) in question were in continuous compliance during the applicable time period.

[4] Compliance status for these sources shall be based on a reasonable inquiry using readily available information.

II. Status for Accidental Release Prevention Program:

A. This facility _______ is subject _______ is not subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act)

B. If subject: The facility ____________ is _________ is not in compliance with all the requirements of section 112(r).

1. A Risk Management Plan __________ will be ________ has been submitted to the appropriate authority and/or the designated central location by the required date.

III. Certification

All information for the Annual Compliance Certification must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B.38. This signed certification document must be packaged with the documents being submitted.

I have reviewed this certification in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this certification are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in § 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of § 25-7 122.1, C.R.S.

____

Printed or Typed Name — Title

____

Signature — Date Signed

NOTE: All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

APPENDIX D

Notification Addresses

1. **Air Pollution Control Division**

Colorado Department of Public Health and Environment
Air Pollution Control Division
Operating Permits Unit
APCD-SS-B1
4300 Cherry Creek Drive S.
Denver, CO 80246-1530

ATTN: Jim King

2. **United States Environmental Protection Agency**

Compliance Notifications:

Office of Enforcement, Compliance and Environmental Justice
Mail Code 8ENF
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

Permit Modifications, Off Permit Changes:

Office of Partnerships and Regulatory Assistance
Mail Stop 8P-AR
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

APPENDIX E

Permit Acronyms

Listed Alphabetically:

AIRS -	Aerometric Information Retrieval System
AP-42 -	EPA Document Compiling Air Pollutant Emission Factors
APEN -	Air Pollution Emission Notice (State of Colorado)
APCD -	Air Pollution Control Division (State of Colorado)
ASTM -	American Society for Testing and Materials
BACT -	Best Available Control Technology
BTU -	British Thermal Unit
CAA -	Clean Air Act (CAAA = Clean Air Act Amendments)
CCR -	Colorado Code of Regulations
CEM -	Continuous Emissions Monitor
CF -	Cubic Feet (SCF = Standard Cubic Feet)
CFR -	Code of Federal Regulations
CO -	Carbon Monoxide
COM -	Continuous Opacity Monitor
CRS -	Colorado Revised Statute
EF -	Emission Factor
EMD -	Electromotive Diesel
EPA -	Environmental Protection Agency
FI -	Fuel Input Rate in Lbs/mmBtu
FR -	Federal Register
G -	Grams
Gal -	Gallon
GMCS -	Gas Migration Control System
GPM -	Gallons per Minute
HAPs -	Hazardous Air Pollutants
HP -	Horsepower
HP-HR -	Horsepower Hour (G/HP-HR = Grams per Horsepower Hour)
LAER -	Lowest Achievable Emission Rate
LBS -	Pounds
M -	Thousand
MM -	Million
MMscf -	Million Standard Cubic Feet
MMscfd -	Million Standard Cubic Feet per Day
N/A or NA -	Not Applicable
NOx -	Nitrogen Oxides
NESHAP -	National Emission Standards for Hazardous Air Pollutants
NSPS -	New Source Performance Standards
P -	Process Weight Rate in Tons/Hr
PE -	Particulate Emissions
PM -	Particulate Matter

PM_{10} -	Particulate Matter Under 10 Microns
PSD -	Prevention of Significant Deterioration
PTE -	Potential To Emit
RACT -	Reasonably Available Control Technology
SCC -	Source Classification Code
SCF -	Standard Cubic Feet
SIC -	Standard Industrial Classification
SO_2 -	Sulfur Dioxide
TPY -	Tons Per Year
TSP -	Total Suspended Particulate
VOC -	Volatile Organic Compounds

APPENDIX F

Permit Modifications

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION
December 15, 2006	Minor Modification	Section II, Condition 15.1	Revise emission limit to reflect increase in throughput and correction to emission factor. ***0.83 tpy increase in actual voc emissions***
		Section II, Condition 15.10	Increase permitted throughput.
	Minor Modification	Section II, Condition 2.9	Revised to indicate that compliance will be monitored using a CEM.
		Section II, Condition 2.8 and Condition 19.5.2	Revised to indicate that compliance with the FCCU opacity limits will be monitored using a COM.
June 15, 2009	Minor Modification	Page following Cover Page	Changed the Responsible Official
		General	The Reg 3 citations were revised throughout the permit, as necessary, based on the recent revisions made to Reg 3. Consent Decree citations were revised to provide more identifying information. "Commerce City Refinery Plant 2 (East)" was added to the cover pager, and the headers and footers. Removed the state-only SO2 limit of 0.3 lbs/bbl/yr limit from the summary tables in Section II.1 thru 3, 5 thru 9 and 11.
		Section I	Revised Condition 1.2 to correctly reflect the attainment status. Included the 1999 and 2005 Consent Decrees in Condition 1.4. Included Section IV, Conditions 3.d and 3.g (last paragraph) as State-only conditions in Condition 1.5. Revised Condition 3 (PSD) to update language and correctly reflect the attainment status. Removed the aviation fuel transfer station (F028), added tank T079 and revised the description of Tank T024 in the table in Condition 5.1.
		Section II.1	Corrected the SO_2 limit of "0.3 lb/bb/yr" to "0.3 lb/bbl/day" in the summary table.
		Section II.2	Revised this condition to include the appropriate emission and heat input limits for the FCCU pre-heater. In addition, language was added to address calculating emissions and demonstrating compliance with the heat input limitations. In addition, requirements were included for NSPS Subpart J, performance testing and submitting a case-by-case MACT application. In addition, Condition 2.9 was revised to specify that the SO_2 CEMS is required by the 2005 consent decree and to include the consent decree language.
		Section II.3	Removed the emissions factors for F004 from the summary table. Included a note at the bottom of the table indicating that no APEN is required for F004. Removed the language in Condition 3.1 regarding calculating emissions from F004.
		Section II.4	Replace "except as provided for in 2.2" with "except as provided for below" in the summary table under Condition 4.4 (opacity).

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION
June 15, 2009	Minor Modification	Section II.5	Condition 5.7 was revised to specify that the H_2S limit is on a rolling twelve month average. The monitoring provisions were revised to specify that the H_2S monitoring system be used. The first paragraph of Condition 5.9 was revised to specify that when the Claus Unit SO_2 CEMS is not operating SO_2 emissions shall be determined in accordance with Appendix H. The 2nd, 3rd and 4th paragraphs of Condition 5.9 were removed and included in Section III.3 of the permit. The 2nd to the last paragraph in Condition 5.9 was revised to include the QA/QC plan provisions in the EPA PSD permit.
		Section II.6	Corrected the reference to "Condition 22.6" to "Condition 22.5" in Condition 6.3.
		Section II.7	Condition 7.1 was revised to reflect the requested emissions limits for the truck loading vapor collection and processing system (includes flare) and truck loading fugitive emissions from equipment leaks and to indicate the new emission factors. Condition 7.1 was revised to remove the sentence regarding aviation fuel transfer. Condition 7.4 was revised to reflect change in the monitored parameter (now thermocouple) and the indicator range for that parameter (500 °F or higher). Added language in Condition 7.2 indicating when H_2S sampling can be discontinued.
		Section II.8	Corrected various permit condition numbers in the summary table.
		Section II.9	Added language in Condition 9.2 indicating when H_2S sampling can be discontinued.
		Section II.15	Revised the permit to include the revised throughput and VOC emission limits for T024. Provisions (emissions and throughput limits) were added to this Condition for Tank T079. Corrected "IV.B.2.c" with "VI.b.2.c" in Condition 15.6.
		Section II.18	Emission limitations were included in this Condition for fugitive equipment leaks from Tank T079. Removed the aviation fuel transfer station (F028). Corrected the emission unit numbering.
		Section II.19	Corrected the permit condition number for the 20% opacity in the summary table.
		Section II.22	Removed the requirement to submit an updated SO_2 compliance plan since this requirement has been fulfilled. Added § 60.105(a)(4)(vi) to Condition 22.5.2.
		Section II.23	Added "Group D" to the list in Condition 23.1.
		Section II.27	Corrected the permit condition number for the wastewater separators in the summary table.
		Section II.32	Added the phrase "and equipment leaks as defined in Subpart CC associated with" after "Truck Docks/R/C/Docks".
		Section II.33	Corrected typos in Conditions 33.84 and 33.86.
		Section II.36	Removed the word "automatically" in Condition 36.8.
		Section III.1	Added the requirements for the Site Remediation MACT (40 CFR Part 63 Subpart GGGGG) to the shield for non-applicable requirements.

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION
June 15, 2009	Minor Modification	Section III.3	The following requirements were included in the table for streamlined conditions: EPA PSD permit conditions 2(a) (monitoring portion only), 4(a) (last phrase only), 4(b), 4(c), 4(d), 4(e) and Appendix A.
		Section IV	Removed the statement in Condition 3.g (affirmative defense provisions) addressing EPA approval and state-only applicability. The portion of these provisions which are state-only enforceable are identified in Section I, Condition 1.4. Replaced the “upset provisions” in Condition 3.d with the “affirmative defense provisions for excess emissions during malfunctions”, note that these are state-only enforceable until approved by EPA in the SIP. Replaced the reference to “upset” in Condition 5 (emergency provisions) and 21 (prompt deviation reporting) with “malfunction”. Added an “and” between the Reg 3 and C.R.S. citations in General Condition 4 (compliance requirements). Added the requirements in Colorado Regulation No. 7, Section V.B (disposal of volatile organic compounds) to General Condition 29.
		Appendices	Replaced Appendices B and C with latest version. The aviation fuel transfer station (F028) was removed from and Tank T079 was added to the tables in Appendices B and C. References to the “East Plant” in Appendices B and C were replaced with “Commerce City Refinery, Plant 2 (East)”. Changed the mailing address for EPA in Appendix D. Included the SO_2 emission calculation methodology in Appendix H.

APPENDIX G

(Reserved)

APPENDIX H

SO_2 Emissions Calculation Methodology

SULFUR DIOXIDE (SO_2) EMISSIONS CALCULATION METHODOLOGY

SUNCOR ENERGY (U.S.A.) INC.

COMMERCE CITY REFINERY

VERSION 7
4/21/09

TABLE OF CONTENTS

LIST OF TABLES

LIST OF APPENDICIES

LIST OF ACRONYMS

AG	acid gas
AMP	Alternative Monitoring Plan
APCD	Air Pollution Control Division
APEN	Air Pollutant Emissions Notice
ASTM	American Society for Testing and Materials
bpd	barrels per day
CAQCC	Colorado Air Quality Control Commission
CDPHE	Colorado Department of Public Health and Environment
CEMS	continuous emissions monitoring system
city gas	purchased, pipeline quality natural gas
Diesel HDS	Diesel Hydrodesulfurization Unit (#3 HDS)
EPA	U.S. Environmental Protection Agency
FCCU	fluidized catalytic cracking unit
FF	fresh feed
FG	fuel gas
FGRU	flare gas recovery unit

GC	gas chromatograph
GOHDS	Gas-Oil Hydrodesulfurization System (#4 HDS)
H_2S	hydrogen sulfide
HDS	Hydrodesulfurization System (#2 HDS)
lb	pounds mass
LPG	liquefied petroleum gas
MMBtu/hr	million British thermal units per hour
Mscf	thousand standard cubic feet
NDS	Naphtha Hydrodesulfurization System (#1 HDS)
NO_x	oxides of nitrogen
PSA	pressure swing adsorption
PLC	programmable logic controllers
ppm	parts per million
Refinery	Commerce City Refinery (WP, including the AU, and EP)
scf	standard cubic foot
scfm	standard cubic feet per minute
SCTU	sweet crude topping unit
SO_2	sulfur dioxide
SRP	sulfur recovery plant
SRU	sulfur recovery unit
Suncor	Suncor Energy (U.S.A.) Inc.
SWS	sour water stripper
SWSG	sour water stripper gas
TGU	tail gas unit
tpy	tons per year

FACILITY DESCRIPTION AND REGULATORY BACKGROUND

Suncor Energy (U.S.A.), Inc., (Suncor) owns and operates the Commerce City Refinery (Refinery) in Commerce City, Colorado. The facility is divided into three operating areas; Plant 1, Plant 2, and Plant 3. Plant 1 is the portion of the heritage Conoco refinery that is located on the west side of Brighton (formerly the West Plant). The heritage Colorado Refining Company facility is now referred to as Plant 2 (formerly the East Plant). The portion of the heritage Conoco facility located on the east side of Brighton Boulevard is now referred to as Plant 3 (formerly the Asphalt Unit). When being referred to as a process unit or when identifiying specific emission points in Plant 3, it is commonly referred to as the #3 Crude Unit. All of these operating areas include various emission units that emit sulfur dioxide (SO_2). Colorado Department of Public Health and Environment Air Pollution Control Division (APCD) Operating Permit Numbers 96OPAD120 (Plant 1 and Plant 3) and 95OPAD108 (Plant 2) issued for the refinery include various limits on SO_2 emissions from these units.

Applicable Regulations

These SO_2 emission units are subject to Colorado Air Quality Control Commission (CAQCC) Regulation 1, Section (§) VI.B.4.e. A petroleum refinery subject to Regulation 1 § VI.B.4.e must meet the following emission limitation for the sum of all refinery SO_2 emissions:

- 0.3 pounds (lb) of SO_2 per barrel of oil processed (averaged over a daily 24-hour period, i.e. midnight through 23:59)

Title V Operating Permits must specifically indicate how compliance with specific applicable requirements will be monitored. This document was prepared to indicate the methods that will be used to monitor compliance with the Regulation No. 1 § VI.B.4.e emission limitation and includes the following:

- How SO_2 emissions are calculated; and

- How the barrels of oil processed are derived, taking into account intermediate storage.

This document is intended to indicate the methods used to monitor compliance with the requirements of Regulation No. 1 § VI.B.4.e.

Other SO_2 Requirements

In addition to indicating how compliance with the provisions of Regulation No. 1 § VI.B.4.e will be monitored, sections of this plan also describe how the Refinery will monitor compliance with other applicable requirements related to SO_2 emissions. This plan covers the compliance monitoring methods for the following additional applicable requirements:

- Regulation No. 6, Part B, § IV.C.2, a state-only refinery-wide limit on SO_2 emissions

- Daily emission limits for an individual unit

- Annual numerical SO_2 emission limits for individual, or grouped, emission units as set forth in the Operating Permits and other documents

- The Plant 2 facility-wide annual SO_2 limit at condition 22.3 of 95OPAD108

- Air Pollutant Emission Notice (APEN) requirements

Regulation No. 6: SO_2 Limit

Regulation 6, Part B, § IV.C.2. limits SO_2 emissions to 0.3 lb of SO_2 for the sum of all SO_2 emissions from a given refining facility per barrel of oil processed (averaged over a daily 24-hour period, *i.e.* midnight through 23:59). This is a state-only standard.

Annual Emission Limits for Individual Units

The Operating Permits include rolling twelve-month SO_2 emission limits on individual emission units. These limits are summarized in Tables 1-1 and 1-2.

Plant 2 Facility-wide Limit

95OPAD108 includes a rolling twelve-month SO_2 emission limit on facility-wide emissions. This limit is summarized in Table 1-2.

APEN Requirements

CAQCC Regulation No. 3, Part A, § II.C, requires a revised APEN to be filed with the Division by April 30th of each year if a significant change in emissions occurred or if modifications were made to control equipment in the previous year, or before an existing APEN expires. The Permits specify that annual SO_2 emission estimates for APEN purposes be based on the procedures outlined in the most current plan for calculating SO_2 emissions.

Table 1-1.
Summary of Rolling 12-Month SO_2 Limits for Individual Units (Plant 1 & 3)

WP Title V Permit ID	SO_2 Emission Limit (tpy) [1]
H-13 – #3 Crude Unit Process Heater	0.87
H-17 – #3 Crude Unit Process Heater	1.89
H-19 – #2 HDS Process Heater	3.44
H-28, H-29, H-30 – Reformer Process Heaters	10.5
H-31, H-32 – #3 HDS Process Heaters	7.66
H-1716, H-1717– #4 HDS Process Heaters	10.3

WP Title V Permit ID	SO_2 Emission Limit (tpy) [1]
H-2101 – H_2 Plant	10.2
H-33, H-37 – Asphalt Unit Process Heaters	8.28
H-25 – TGU Incinerator	171.70
B-6 – Boiler	12.70
B-8 – Boiler	18.40

Notes:

1 SO_2 emission limits presented in the Operating Permit (April 2006).

HDS = Hydrodesulfurization
TGU = Tail Gas Unit
SO_2 = sulfur dioxide
tpy = tons per year

Table 1-2.
Summary of Rolling 12-Month SO_2 Limits for Plant 2

EP Title V Permit ID	SO_2 Emission Limit (tpy)[1]
B001 – Crude Heater	17.77
B010 – Vacuum Heater	6.13
Heater 1, 2, 3 – Reformer Heaters	26.0
Sulfur Recovery Plant	344.0
B003, B004, B005 – Boilers #1, #2, and #3	18
Main Refinery Flare	172.0
Rail Car Dock Flare	1.0
Security Center Emergency Generator[2]	0.01
Soil Extraction Vapor System[2]	0.0015
Facility Total (per 95OPAD108, Condition 22.4)	1926.3

Notes:

1 SO_2 emission limits presented in the Operating Permit (October 2006).

2 For purposes of calculating facility total SO_2 emissions the contribution from these sources are not included (per 95OPAD108, Condition 22.4).

Document Organization

The document specifies how compliance with the previously described requirements will be monitored. Section 2.0 identifies the sources of SO_2 at the Refinery. Section 3.0 describes how SO_2 emissions will be determined for the identified sources. Section 4.0 describes the procedure for determining the barrels of oil processed. Section 5.0 describes the procedure for demonstrating compliance with the Regulation No. 1 and Regulation No. 6 limits on SO_2 emissions per bpd oil processed and with other applicable regulations and permit mass emission limits. Section 6.0 describes record keeping and reporting procedures.

IDENTIFICATION OF SOURCES

Because crude oil coming into the refinery contains sulfur, a by-product of refining is SO_2. A large majority of the incoming sulfur is removed in the amine unit as hydrogen sulfide (H_2S) that is then converted to elemental sulfur in the sulfur recovery plants (SRP). The remaining sulfur stays with hydrocarbon products or moves through the refining process in a gaseous state. When the sulfur-containing gas is combusted, SO_2 is generated.

For purposes of this document, the primary sulfur-bearing compound in gas or liquid streams is considered to be H_2S. There are other trace chemical compounds containing sulfur, such as mercaptans, carbonyl sulfide, and carbon disulfide, however these compounds exist at much lower concentrations within the affected streams and are not routinely monitored throughout the facility.

Sources with similar proposed SO_2 emission rate calculation methodologies are grouped together for convenience in this document.

Boilers and Process Heaters

Boilers and process heaters at the Refinery are listed in Table 2-1. Fired boilers and process heaters are grouped together in the document because their SO_2 emissions result from the combustion of refinery fuel gas or purchased pipeline quality natural gas (“city gas”). Gases are produced at a variety of locations within the refinery from refinery process gas streams. These gases are treated to remove sulfur and managed in the Refinery’s fuel gas system. The Commerce City Refinery has two refinery fuel gas systems (one for Plants 1 & 3 and one for Plant 2), which are continuously monitored for H_2S concentration. SO_2 emissions from the combustion of refinery fuel gas are a function of the H_2S concentration of the fuel gas and the volume of fuel gas combusted. City gas is purchased from off-site and also contains some sulfur bearing compounds that result in the formation of SO_2 during combustion. When the city gas is combined with fuel gas, the combination occurs at the applicable fuel gas drum, and the outlet from the fuel gas drum is the compliance point. In some instances city gas is directly fed to pilot gas systems and is not monitored as part of the fuel gas system.

A detailed description of the SO_2 emissions calculation methodology for heaters and boilers is provided in Section 3.1.

Process Units

Process units at the refinery that emit SO_2 are shown in Table 2-2. These sources combust or process either refinery fuel gas, city gas, acid gas streams, or process sulfur-containing feed streams, resulting in emissions of SO_2 during operation.

The Fluidized-bed Catalytic Cracking Units (FCCUs) process refinery streams into gasoline, diesel fuel, and other products. The FCCU regenerators are used to oxidize residual coke and carbon from the catalyst used in the FCCU. The residual coke or carbon contains trace quantities of sulfur, which is emitted as SO_2 during the process of regenerating the cracking catalyst.

Table 2-1.
Boilers and Process Heaters at the Refinery

Title V Permit ID	Source Description
Plants 1 & 3	
H-6	Radco Inc. SN SJ502 14.4 MMBtu/hr Vacuum Tower Preheater
H-16	Radco Inc. 6.0 MMBtu/hr Asphalt Heater
H-18	Empire 6.0 MMBtu/hr Asphalt Heater
H-20	Radco Inc. 14.0 MMBtu/hr NDS Heater
H-22	Born Engineering Inc. 59.76 MMBtu/hr FCCU Heater
H-10	Tulsa Heaters Inc. H10/N/A 34.02 MMBtu/hr Reformer Heater
H-11	K.W. Aldelson SN89379 29.76 MMBtu/hr Vacuum Tower Heater
H-27	Radco Inc. H27/SJ480 76.48 MMBtu/hr Crude Preheater
B-4	Henry Vogt Machine Co. Model WSPSN 1986 130.0 MMBtu/hr steam boiler
B-6	Zurn Industries Inc. Model 898307 SN10056 111.0 MMBtu/hr steam boiler
B-8	Zurn Industries Inc. SN 98974 161.0 MMBtu/hr steam boiler
H-13	One Radco Inc. S/N 352, refinery fuel gas fired process heater, 6.8 MMBtu/hr, for heating asphalt
H-17	One Custom S/N 352 refinery fuel gas fired process heater, 58.4 MMBtu/hr, for heating asphalt
H-19	One custom built, Model H-19, S/N SJ-114, refinery fuel gas fired heater, 29.18 MMBtu/hr, for heating of distillate oil charge to the Distillate Oil Hydrodesulfurizer
H-28	Refinery fuel gas fired reformer heaters: Radco S/N 369; Radco S/N 370; and Radco S/N 368. Total heat input rating: 88.6 MMBtu/hr, emissions from common stack
H-29	
H-30	
H-31	One custom built, Model H-31 refinery gas fuel fired heater, 23.56 MMBtu/hr, for heating of diesel charge to the #3 Hydrodesulfurizer
H-32	One custom built, Model H-32 refinery fuel gas fired heater, 37.8 MMBtu/hr, for heating of Fractionator Unit
H-33	One custom built, Model H-33 refinery fuel gas fired heater, 7.68 MMBtu/hr, for heating asphalt in the #3 Crude Unit. Equipped with Ultra Low NO_x burners
H-37	One custom built, Model H-37 refinery fuel gas fired heater, 57.24 MMBtu/hr, for heating of asphalt in the #3 Crude Unit
H-25	One custom built, refinery fuel gas fired tail gas incinerator, 15 MMBtu/hr, for reduction of sulfur emissions from the Sulfur Recovery Plant
H-1716	One custom built, refinery fuel gas fired heater, 53.6 MMBtu/hr, for heating of gas-oil charge to the # 4 Gas Oil Hydrodesulfurizer
H-1717	One custom built, refinery fuel gas fired heater, 36.8 MMBtu/hr, for heating of gas-oil charge to the #4 Gas Oil Hydrodesulfurizer
H-2101	One custom built, natural gas/PSA reject gas fired methane reformer heater, 331 MMBtu/hr, for production of purified H_2 in the H_2 Plant

Title V Permit ID	Source Description
Plant 2	
B-1	Nebraska Boiler, Model 81-832-5, S/N: 98842, 75 MMBtu/hr
B-2	Nebraska Boiler, Model NS-E-59, S/N: D-2324, 75 MMBtu/hr
B-3	Nebraska Boiler, Model NS-E-61, S/N: 202011, 75 MMBtu/hr
B002	Petrochem, Model C-61145, (vacuum heater), 59.44 MMBtu/hr
B003	Heater 1, John Zink, Drg. No.: B-Y 11673, S/N: 099274-1, refinery fuel gas fired preheater, 64.4 MMBtu/hr
B004	Heater 2, John Zinc, Drg. No.: B-Y 11674, S/N: 099274-2, refinery fuel gas fired preheater, 64.4 MMBtu/hr
B005	Heater 3, John Zink, Drg. No.: B-y 11675, S/N: 099274-3, refinery fuel gas fired preheater, 32.2 MMBtu/hr
B001	OPF, S/N: 5450-1240, refinery fuel gas fired crude heater, 153 MMBtu/hr
B010	PetroChem., S/N: 86-F-1497, refinery fuel gas fired FCCU preheater, 31 MMBtu/hr

Notes:

MMBtu/hr = million British thermal units per hour

NO_x = oxides of nitrogen

FCCU = Fluidized Catalytic Cracking Unit

NDS = naphtha De-sulfurizer

Table 2-2.
Process Units at the Refinery

Title V Permit ID	Source Description
Plants 1 & 3	
P101	One two-stage Claus Sulfur Recovery Unit, followed by a TGU and a Tail Gas Incinerator – #1 SRU
P102	One three-stage Claus Sulfur Recovery Unit, followed by a TGU and a Tail Gas Incinerator – #2 SRU
H-25 TGU Incinerator	One custom built, TGU with refinery fuel gas fired incinerator, 15,000,000 Btu/hour, for control of SO_2 emissions from sulfur recovery units (SRU) #1 and #2
P103	FCCU Regenerator
Plant 2	
P004	FCCU Regenerator
P009	One three-stage Claus sulfur recovery system, 30 mmscf/day acid gas feed, sulfur recovery of 4.5 tons (4.0 long tons) per day – 1.95 MMBtu/hr tail gas incinerator

Notes:

FCCU = Fluidized Catalytic Cracking Unit

SRU = Sulfur Recovery Unit

TGU = Tail Gas Unit

The Plant 1 SRP includes the Number 1 Sulfur Recovery Unit (#1 SRU, a two-stage Claus process), the Number 2 Sulfur Recovery Unit (#2 SRU, a three-stage Claus process), and Tail Gas Unit (TGU). In the TGU, sulfur compounds in the tail gas from the #1 and #2 SRUs are converted to H_2S. The hydrogenated tail gas (rich in H_2S) is then sent to the amine treating section of the TGU and is reduced to lean gas (low in H_2S). The acid gas effluent from the amine regenerator is recycled back to the SRUs for further processing. The H_2S in the lean gas is then oxidized to SO_2 in the TGU incinerator (H-25), which is the point of emission to the atmosphere.

The Plant 2 SRP includes the Amine Unit, Sour Water Stripper (SWS), Claus Unit, and Tail Gas Incinerator. The Amine Unit removes sulfur from refinery process gas in the form of H_2S. The SWS uses steam to strip H_2S from process water. The gas stream containing the stripped H_2S from these units is called acid gas. The Claus Unit converts the H_2S in the acid gas into elemental sulfur. Because the SRP cannot operate at 100% efficiency, some H_2S is carried through the Claus Unit and is oxidized to SO_2 in the Tail Gas Incinerator.

Flares

Flares at the Refinery that emit SO_2 are shown in Table 2-3.

The Plant 1 Main Plant (MP) Flare is used for safely combusting gas streams resulting from startups, shutdowns and malfunction conditions that occur within Plant 1; inadvertent leakage from relief valves and similar equipment, vapors from miscellaneous process vents, and any excess refinery fuel gas that is not combusted in boilers or heaters. The Plant 1 MP Flare system includes a Flare Gas Recovery Unit (FGRU) that during normal operations is used to recover gas streams that were previously flared and are now recovered into the refinery fuel gas system. To maintain adequate flare system flows required to prevent oxygen from entering the flare system, a city gas sweep flow is continuously vented through the system downstream of the FGRU. Only during malfunctions in the FGRU, or during periods where refinery-derived gas streams are produced at a rate greater than the capacity of the FGRU, are gas streams combusted in the Plant 1 Flare. SO_2 emissions from the Plant 1 flare are a function of the H_2S concentration in the combusted gas and the volume of gas combusted. There is also a contribution from the combustion of city gas in the flare pilot.

The #3 Crude Unit (Plant 3) Flare is used to safely combust gas streams resulting from startups, shutdowns, or malfunctions in the #3 Crude Unit. The #3 Crude Unit Flare system also includes a FGRU (separate from the Plant 1 MP FGRU) that during normal operations is used to recover gas streams that were previously flared and are now recovered into the refinery fuel gas system. To maintain adequate flare system flows required to prevent oxygen from entering the flare system, a city gas sweep flow is continuously vented through the system downstream of the FGRU. Only during malfunctions in the FGRU, or during periods where #3 Crude Unit derived gas streams are produced at a rate greater than the capacity of the FGRU, are #3 Crude Unit gas streams combusted in the #3 Crude Unit Flare. SO_2 emissions from the #3 Crude Unit Flare are a function of the H_2S concentration in the sweep gas and the volume of gas combusted. There is also a contribution from the combustion of city gas in the flare pilot.

The Plant 2 MP Flare is used for safely combusting gas streams resulting from startups, shutdowns and malfunction conditions that occur within Plant 2; inadvertent leakage from relief valves and similar equipment, vapors from miscellaneous process vents, and any excess refinery fuel gas that is not combusted in boilers or heaters. SO_2 emissions from the Plant 2 MP flare are a function of the H_2S concentration in the combusted gas and the volume of gas combusted. There is also a contribution from the combustion of city gas in the flare pilot.

The Plant 1 and Plant 2 Truck Rack Flares combust hydrocarbon vapors generated from loading truck tanks with petroleum products. The Plant 1 Truck Rack flare system utilizes a three-stage flare operating in a demand-based mode. Operation of one burner stage is required for any loading activity to proceed. As the quantity of product loaded at a given point in time increases, the second and third burner stages may be activated to provide sufficient capacity to flare the recovered vapors. The Plant 2 Truck Rack Flare is actually an enclosed combustor. This rack also works in a demand-based mode similar to the Plant 1 Truck Rack Flare. With respect to the calculation of SO_2 emissions from these two sources there is no difference. SO_2 emissions from the Plant 1 and Plant 2 Truck Rack Flares are a function of the H_2S concentration in the combusted gas and the volume of gas combusted. There is also a contribution from the combustion of city gas in the flare pilot.

The Plant 1 and Plant 2 Rail Rack Flare Systems are designed to burn off non-recoverable gases and vapors from loading of railroad tank cars with refined petroleum products. Their main purpose is to provide a safe means of disposal for flammable material that may be released from petroleum product loading and unloading activities. SO_2 emissions from the Plant 1 and Plant 2 Rail Rack Flares are a function of the H_2S concentration in the combusted gas and the volume of gas combusted. There is also a contribution from the combustion of propane in the flare pilot.

Table 2-3.
Flares at the Refinery

Title V Permit ID	Description
Plants 1 & 3	
R101	Rail Loading Rack
R102	Truck Loading Rack
F1	Plant 1 MP Flare
F2	#3 Crude Unit Flare
Plant 2	
C005	Plant 2 MP Flare
Truck Rack Flare	Plant 2 Truck Loading Rack
Rail Car Dock Flare	Plant 2 Rail Loading Rack

Notes:

AU = Asphalt Unit MP = Main Plant

EP = East Plant WP = West Plant

Malfunction Emissions

In certain malfunction events, SO_2 emissions may be generated that are not quantified in the above-described SO_2 source types. Typically these events are limited to the Plant 1 MP Flare, the Plant 2 MP Flare or the #3 Crude Unit Flare, or the process units. In this case, Refinery engineering, operations, and environmental staff work to determine the quantity of SO_2 that was released based on available process data, stream data, and professional judgment. These malfunction related emissions are added to the daily total when the details of the malfunction event have been investigated. In the case that more than one malfunction occurs on a given day, each malfunction event may be reported separately, or as a combined daily emission estimate.

Emergency Generator

A new diesel fired stationary internal combustion compression ignition emergency generator was installed in 2008. This source is not currently included in the Title V permit however SO_2 emissions from this source will be included in the demonstration of compliance with the applicable emissions limitations. Emissions of SO_2 result solely from the combustion of ultra-low sulfur diesel.

Soil Vapor Extraction

Suncor operates soil vapor extraction (SVE) units to recover hydrocarbon vapor from soil at various sites at the Commerce City Refinery and combust the collected vapor as part of ongoing and future remediation projects. In the SVE unit, the recovered hydrocarbon vapors extracted from the soil are combusted in either a trailer mounted internal combustion engine or in a thermal oxidizer (depending on which system is being used). In the event that the recovered soil vapor does not provide sufficient fuel to support combustion, supplementary commercial grade propane (not generated at the refinery) is used. SO_2 emissions from this activity are the result of the combustion of trace amounts of sulfur bearing species in these two gas streams.

SULFUR DIOXIDE EMISSIONS ESTIMATES

The categories of emission units that emit SO_2 and the methods used to estimate the SO_2 emissions are summarized in Table 3-1 and described in detail in Sections 3.1 through 3.5.

Table 3-1.
Summary of SO_2 Emission Estimation Methods

Section	Source Description	Estimation Method
3.1	Boilers and Process Heaters	Fuel gas H_2S monitor and fuel gas consumption rate
3.2	#1 FCCU Regenerator	CEMS monitoring data and exhaust flow measurement
	#2 FCCU Regenerator	Stack test emission factors
3.3	Plant 1 SRP	CEMS monitoring data, mass balances, and exhaust flow measurements
3.3	Plant 2 SRP	CEMS monitoring data and parametric exhaust flow calculations
3.4	Plant 1 & 3 Refinery Flares	Flare gas H_2S sample and engineering data, flow measurements
	Plant 2 Refinery Flares	Flare gas H_2S monitor data and engineering data, flow measurements

Section	Source Description	Estimation Method
3.5	Malfunction Emission	Engineering assessment/process knowledge

Notes:

H_2S = hydrogen sulfide

CEMS = Continuous Emissions Monitoring System

FCCU = Fluidized Catalytic Cracking Unit

SRP = Sulfur Recovery Plant

Fuel Gas Combustion

The SO_2 emissions from the boilers and process heaters are calculated based on the volume of fuel gas combusted and the concentration of H_2S in the combusted fuel gas. The boilers and process heaters are shown in Table 2-1. Both the volume of gas combusted in each of these units and the H_2S concentration of the fuel gas combusted are monitored by the Refinery data management system.

The concentration of H_2S in the fuel gas (FG) is typically reported in terms of parts per million (by volume). The following relationship is used to convert ppm H_2S to pounds SO_2 per 1 million (1,000 Mscf) standard cubic foot of gas:

$$\frac{\text{X scf } H_2S}{1\text{x}10^6 \text{ scf FG}} \times \frac{1\text{x}10^6 \text{ scf FG}}{1{,}000 \text{ Mscf FG}} \times \frac{0.0900 \text{ lb } H_2S}{\text{scf } H_2S} \times \frac{1.8824 \text{ lb } SO_2}{\text{lb } H_2S} = \frac{0.169 \text{ lb } SO_2}{1{,}000 \text{ Mscf FG}}$$

<u>Calculation Method for Daily Emissions</u>

For the purpose of calculating daily SO_2 emissions for boilers and process heaters for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method is as follows:

$$\frac{\text{Fuel gas flow (Mscf)}}{\text{day}} \times \frac{H_2S \text{ conc (ppm)}}{1} \times \frac{0.169 \text{ lb } SO_2}{\text{ppm } H_2S - 1{,}000 \text{ Mscf FG}} = \frac{\text{lb } SO_2}{\text{Day}}$$

Where:

Fuel gas flow = fuel gas flow rate to fired unit (Mscf/day)

H_2S conc, = Measured concentration of H_2S in the fuel gas (ppm by volume)

lb SO_2/day = lb of SO_2/day from combustion of fuel gas.

The volume of gas combusted in each unit is measured at one-minute intervals and averaged over 24 hours starting at midnight. In Plants 1 & 3, the H_2S content in the fuel gas is measured at least once per 15 minutes in the fuel gas mix drum (D-193) using a continuous gas chromatograph (GC) continuous emission monitoring system. In the EP, the volume of gas combusted in each unit is measured continuously using an orifice plate and averaged over 24 hours starting at midnight. The H_2S content in the fuel gas is measured at least once per

15-minute interval downstream of the fuel gas mix drums (54-V-1 and 54-V-2) using a GC continuous emission monitoring system.

In either plant, City gas or stored propane can be added to the refinery fuel gas system at a point upstream of the monitoring system, in which case the GC will report the combined H_2S concentration of the refinery fuel gas stream with the additional city gas and/or propane added in. GC measurements are averaged over the 24-hour period, starting at midnight.

The Plant 1 Hydrogen Plant Steam Methane Reforming Furnace, H-2101, is designed to burn a mixture of city gas and pressure swing adsorption (PSA) reject gas. PSA reject gas is essentially free of sulfur because it is previously scrubbed to remove all sulfur prior to entering the Hydrogen Plant.

Fuel gas consumption for Plant 3 heaters H-16 and H-18 is not directly measured. These units are assumed to operate at maximum fired duty at all times.

Calculation Method for Annual Emissions

The boilers and process heaters that have rolling 12-month SO_2 emission limits are shown in Tables 1-1 and 1-2. The #2 FCCU preheater does not have an annual SO_2 emission limit. Fuel gas combustion sources in Plant 2 are included in calculating the Plant 2 facility-wide rolling 12-month emissions to monitor compliance with its facility-wide emission limit. For the purpose of calculating SO_2 emissions for fuel gas combustion sources for comparison with rolling 12-month permit limits, the calculation method is as follows:

Tons SO_2 /year = ∑ [Tons of SO_2 /month] for the current month plus the 11 preceding months

Where:

Tons of SO_2 /month = [Sum of daily emissions for the days in the month]

To calculate SO_2 emissions from the boilers and process heaters for APEN purposes, the calculation method is as follows:

Tons SO_2 /year = ∑ [Tons of SO_2/month] for January through December of the reporting year

Where:

Tons of SO_2 /month = [Sum of daily emissions for the days in the month]

Regarding calendar year limits for APEN reporting purposes, the above calculation is performed for the 12 months in the calendar year (January through December) per CAQCC Regulation No. 3, Part A, § II.B.6.

FCCU Regenerators

The FCCU Regenerators are used to burn the carbon off of the catalyst used to crack the FCCU feed. Because the regeneration process relies on exothermic combustion processes, any sulfur that is on or in the catalyst media is converted to SO_2.

The SO_2 emissions from the #1 and #2 FCCU Regenerators are calculated based on the continuous emissions monitoring system (CEMS) data and FCCU Regenerator stack gas flow rates.

Calculation Method for Daily Emissions

Plant 1

For the purpose of calculating daily SO_2 emissions for the #1 FCCU Regenerator for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method is as follows:

$$\frac{SO_2 \text{ ft}^3 \text{ (dry, zero } O_2)}{1{,}000{,}000 \text{ ft}^3 \text{ stack flow}} \times \text{Stack Flow (scfm, dry)} \times \frac{9.97 \text{ min-lb } SO_2}{\text{hr-ft}^3\ SO_2} = SO_2 \text{ (lb/hr)}$$

Where:

Stack Flow (scfm, wet) = Process flow analyzer value for stack exhaust gas flow, wet

$$\text{Stack Flow (scfm, wet)} \times \frac{(100\% - \text{x.xx }\%\ H_2O)}{100\%} = \text{Stack Flow (scfm, dry)}$$

x.xx% = sample moisture content (following H_2O removal in sample train, sample moisture content verified during required Relative Accuracy Test Audit and most recent measurement will be used to calculate emissions, typical value is 8.7%)

Stack Flow (scfm, dry) = Process flow analyzer value for stack exhaust gas flow, corrected for exhaust gas moisture, reported as dry.

9.97 min-lb SO_2 / hr-ft^3 SO_2 = unit conversion constant for SO_2.

$$\frac{60 \text{ min}}{\text{hr}} \times \frac{\text{lb-mol } SO_2}{358.4 \text{ ft}^3\ SO_2 \text{ (at 68° F)}} \times \frac{64.063 \text{ lb } SO_2}{\text{lb-mol SO2}} = \frac{9.97 \text{ min-lb } SO_2}{\text{hr-ft}^3\ SO_2}$$

$$SO_2 \text{ ft}^3 \text{ (dry)} \times 20.90\% = SO_2 \text{ ft}^3 \text{ (dry, zero } O_2)$$

1,000,000 ft^3 stack flow   20.90% - %O_2 (dry)   1,000,000 ft^3 stack flow

SO_2 (dry) = stack gas concentration (by volume) of SO_2 measured by CEMS, corrected for water vapor, reported as dry.

20.90% = atmospheric O_2 content

%O_2 (dry) = stack gas concentration of O_2 measured by CEMS, corrected for water vapor.

SO_2 (dry, zero O_2) = concentration (by volume) of SO_2 measured by CEMS, corrected for water vapor and reported at 0% O_2.

The calculations described above occur within the programmable logic controllers (PLC) for the CEMS system prior to being uploaded to the Plant Information system (PI, the data historian). The calculations are performed once per second to obtain a pound SO_2 emitted per second value. Within a given hour, all 3,600 1-second readings are summed, and within a given day all 24 1-hour readings are summed. The pound SO_2 per day value is used to determine compliance with the emission limit.

Tons of SO_2 /day =∑ [Sum of hourly emissions during the operating day]

Plant 2

For the purpose of calculating daily SO_2 emissions from the #2 FCCU Regenerator for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method is as follows:

$$\frac{SO_2\ ft^3\ (\text{dry, zero } O_2)}{1{,}000{,}000\ ft^3\ \text{stack flow}} \times \text{Stack Flow (scfm, dry)} \times \frac{9.97\ \text{min-lb}\ SO_2}{\text{hr-}ft^3\ SO_2} = SO_2\ (\text{lb/hr})$$

Where:

Stack Flow (acfm) is calculated per MACT UUU, 40 CFR §63.1573(a)(1)(i)) equation (1), as follows:

$$\frac{1.12\ \text{scfm}}{\text{scfm, dry}} \times Q_{air} + Q_{other}\ (\text{scfm, dry}) \times \frac{T_{gas}\ (^{o}K)}{293\ (^{o}K)} \times \frac{1atm}{P_{vent}} = Q_{gas}\ (\text{acfm})$$

Q_{gas}= Hourly average actual gas flow rate, acfm;

1.12 = Default correction factor to convert gas flow from dry standard cubic feet per minute (dscfm) to standard cubic feet per minute (scfm);

Q_{air}= Volumetric flow rate of air to regenerator, as determined from the control room instrumentations, dscfm;

Q_{other}= Volumetric flow rate of other gases entering the regenerator as determined from the control room instrumentations, dscfm. (Examples of "other" gases include an oxygen-enriched air stream to catalytic cracking unit regenerators and a nitrogen stream to catalytic reforming unit regenerators.);

$Temp_{gas}$= Temperature of gas stream in vent measured as near as practical to the control device or opacity monitor, °K. For wet scrubbers, temperature of gas prior to the wet scrubber; and

P_{vent} – Absolute pressure in the vent measured as near as practical to the control device or opacity monitor, as applicable, atm. When used to assess the gas flow rate in the final atmospheric vent stack, Suncor assumes P_{vent} = 1 atm.

Calculation Method for Annual Emissions

Plant 1

The #1 FCCU Regenerator is not subject to a rolling 12-month SO_2 emission limit. For the purpose of calculating SO_2 emissions from the #1 FCCU Regenerator for APEN purposes, the calculation method is as follows:

Tons SO_2 /year = ∑ [Tons of SO_2/month] for January through December of the reporting year

Where:

Tons of SO_2 /month = ∑ [Sum of daily emissions for the days in the month]

Regarding calendar year limits for APEN reporting purposes, the above calculation is performed for the 12 months in the calendar year (January through December) per CAQCC Regulation No. 3, Part A, § II.B.6.

Plant 2

The #2 FCCU Regenerator is not subject to a rolling 12-month SO_2 emission limit. For the purpose of calculating SO_2 emissions from the #2 FCCU Regenerator for APEN purposes, the calculation method is as follows:

Tons SO_2 /year = ∑ [Tons of SO_2/month] for January through December of the reporting year

Where:

Tons of SO_2 /month = ∑ [Sum of daily emissions for the days in the month]

Regarding calendar year limits for APEN reporting purposes, the above calculation is performed for the 12 months in the calendar year (January through December) per CAQCC Regulation No. 3, Part A, § II.B.6.

Sulfur Recovery Plants

Sources included in the Plant 1 SRP are the Number 1 Sulfur Recovery Unit (#1 SRU), the Number 2 Sulfur Recovery Unit (#2 SRU), and Tail Gas Unit (TGU).

The #1 SRU is a two-stage Claus process, and the #2 SRU is a three-stage Claus process. The TGU is a custom-built unit that processes off-gas from both #1 SRU and #2 SRU. In the TGU sulfur compounds such as SO_2, carbonyl sulfide, carbon disulfide, and elemental sulfur in the tail gas from the #1 and #2 SRUs are catalytically converted to H_2S in the hydrogenation section of the TGU. This tail gas stream from the SRUs is fed into the Reducing Gas Generator where it is mixed with sub-stoichiometric combustion products of natural gas and air to enable the hydrogenation reaction. The hydrogenated tail gas (rich in H_2S) is then sent to the amine treating section of the TGU. A circulating amine solution adsorbs the H_2S gas and some CO_2 from the tail gas and reduces the lean H_2S content to approximately 100 ppmv. The acid gas effluent from the amine regenerator is recycled back to the SRUs for further processing. The H_2S in the lean gas from the amine absorber and other trace sulfur compounds are then oxidized in the TGU incinerator (H-25), which is the point of emission to the atmosphere.

Vents from the #1 SRU sulfur pit and the #2 SRU sulfur storage tanks are also vented and oxidized in the TGU incinerator (H-25). The SWS off gas is processed within the SRUs.

The TGU Incinerator (H-25) is equipped with a CEMS unit that monitors SO_2 and O_2 concentrations in the exhaust and a flow measurement device to determine stack gas flow.

The Plant 2 SRP includes the SWS, the Amine Unit and Claus Unit, and the Tail Gas Incinerator. The Claus Unit converts H_2S in the Amine Unit off-gas, or acid gas, to elemental sulfur. The SWS removes H_2S from process water by steam stripping H_2S out of the process water and the resultant vapor is sent to the Claus Unit for sulfur removal along with the Amine Unit off-gas. Because the Claus unit cannot operate at 100% sulfur removal efficiency, a small amount of H_2S is carried through the unit and oxidized to SO_2 in the Tail Gas Incinerator. The SO_2 value for the Plant 2 SRP will be calculated using a mass balance based on measured SO_2 concentration in the Plant 2 SRU Incinerator exhaust and a parametric method for calculating SRU Incinerator exhaust flows.

Plant 1 SRP (TGU Incinerator H-25)

Emissions of SO_2 from the TGU incinerator are calculated using CEMS data.

Calculation Method for Hourly Emissions

For the purpose of calculating hourly SO_2 emissions for the Plant 1 TGU incinerator for use in monitoring compliance with Operating Permit 96OPAD120 Condition 23.1, the calculation method is as follows:

The input parameters are:

O_2 (%)

SO_2 (ppm @ stack O_2 & 60 °F, low range)

SO_2 (ppm @ stack O_2 & 60 °F, high range)

Exhaust flow (scfm [@ stack O_2 & 60 °F])

Calculation 1: Convert stack O_2, low-range SO_2 to 0% O_2

(20.90% - 0% O_2) / (20.90% - Stack O_2%) x SO_2 (ppm @ stack O_2 & 60 °F, low range)

Calculation 2: Convert stack O_2, high-range SO_2 to 0% O_2

(20.90% - 0% O_2) / (20.90% - Stack O_2%) x SO_2 (ppm @ stack O_2 & 60 °F, high range)

Calculation 3: Create Composite SO_2 (ppm @ Stack O_2, 60 °F, instantaneous) concentration value

Because the TGU stack is equipped with two CEMS, one reporting low range (0-495 ppmvd) one reporting over a high range (1 to 4%), a composite SO_2 concentration is tracked.

If the low-range SO_2 (ppm @ stack O_2 & 60 °F, low range) is less than 495 ppmvd, then the low-range analyzer must be used.

If the low-range SO_2 (ppm @ stack O_2 & 60 °F, low range) is greater than 495 ppmvd, then the high-range analyzer must be used.

Calculation 4: Calculation of SO_2 mass emissions

SO_2 (lb/hr, instantaneous) = Composite SO_2 (ppm @ stack O_2, 60 °F, instantaneous) x Stack Flow (scfm, instantaneous) x Correction Factor

Where the Correction Factor (SO_2 specific) is calculated as:

$$\frac{1\ ft^3\ SO_2}{1{,}000{,}000\ ft\ SO_2 - ppm} \times \frac{lbmole\ SO_2}{359.04\ ft^3\ SO_2} \times \frac{491.67\ R}{519.67\ R} \times \frac{12.12\ psia}{14.7\ psia} \times \frac{64.05\ lb\ SO_2}{lbmole\ SO_2} \times \frac{60\ min}{1\ hr} = 8.3495\ E\text{-}06$$

The correction factor changes the molar volume constant from 1 atm, 0 °C to 12.12 psia, 60 °F per EPA guidance and converts time from 1 minute (exhaust flow rate time span) to 1 hour.

<u>Calculation Method for Daily Emissions</u>

For the purpose of calculating daily SO_2 emissions for the TGU incinerator for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method is as follows:

lbs SO_2 /day = ∑ [lb SO_2/hour] for the 24 hours of the reporting day

Regarding CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 reporting purposes, the above calculation is performed for each 24-hour period, beginning at midnight.

Calculation Method for Annual Emissions

The TGU incinerator has a rolling 12-month SO_2 emission limit. For the purpose of calculating SO_2 emissions from the TGU incinerator for comparison with the permitted rolling 12-month emission limits (Operating Permit 96OPAD120 Condition 23.1), the calculation method is as follows:

Tons SO_2 /12 month period = ∑ [Tons of SO_2/month] for current month plus preceding 11 months.

Where:

Tons of SO_2 /month = [Sum of daily emissions for the days in the month]

To calculate SO_2 emissions from the TGU incinerator for APEN purposes, the calculation method is as follows:

Tons SO_2 /year = ∑ [Tons of SO_2/month] for January through December of the reporting year

Where:

Tons of SO_2 /month = [Sum of daily emissions for the days in the month]

Regarding calendar year limits for APEN reporting purposes, the above calculation is performed for the 12 months in the calendar year (January through December) per CAQCC Regulation No. 3, Part A, § II.B.6.

Plant 2 SRP

The SO_2 emissions for the Plant 2 SRP are calculated based on a mass balance using measured SO_2 concentrations in the SRU Incinerator exhaust stack obtained from the certified continuous emissions monitoring system and a calculated SRU Incinerator exhaust flow rate. Due to the low flow rates in the Incinerator exhaust, directly measured stack flows cannot be obtained. A calculation based flow estimate can be prepared using various operating parameters, feed rates, and combustion/thermodynamic principles. The section provides the details regarding the calculation of the flow rate and how this is used to calculate a daily SO_2 emission mass rate.

Calculation Method for Daily Emissions

For the purpose of calculating daily SO_2 emissions for the Plant 2 SRP for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method is as follows:

Lbs of SO_2 /day from SRP = [SRU Incinerator exhaust flow rate (Mscf/day, calc. 1)] x [SO_2 concentration in SRU Incinerator exhaust (lb/Mscf at stack O_2, calc. 2)]

Calculation 1: Plant 2 SRU Incinerator Flow Rate

There are four primary process streams that are introduced to the Claus Unit: the amine acid gas stream, the SWS gas, reaction air, and fuel. Each of these streams is monitored as a process variable (Mscf/day). The reactant stream flow rates are converted to a molar loading rate using stream speciation data to determine the products of the following standard combustion reactions occurring in the Claus Unit:

List of Net Reactions in Claus Reactor

$$3\ H_2S + 3/2\ O_2 \text{-->} 3S + 3\ H_2O$$

$$2NH_3 + 3/2\ O_2 \text{-->} N_2 + 3H_2O$$

$$H_2 + 1/2O_2 \text{-->} H_2O$$

$$CH_4 + 2O_2 \text{-->} CO_2 + 2H_2O$$

$$C_2H_6 + 7/2O_2 \text{-->} 2CO_2 + 3H_2O$$

$$C_3H_8 + 5O_2 \text{-->} 3CO_2 + 4H_2O$$

The Claus unit reaction products are then passed as tail gas to the SRU Incinerator where excess H_2S is combusted to form additional SO_2. This process requires additional fuel introduced through the incinerator burner that is monitored as a process variable (Mscf/d). The combined tail gas and incinerator fuel mixture is mixed with combustion air in the incinerator, however this stream is not measured as a process variable. Using data supplied by the SRU oxygen CEMS, a measured excess oxygen level is used to solve the following combustion reactions to determine the amount of combustion air required.

Incinerator Reactions

$$CH_4 + 2O_2 \text{-->} CO_2 + 2H_2O$$

$$C_2H_6 + 7/2O_2 \text{-->} 2CO_2 + 3H_2O$$

$$C_3H_8 + 5O_2 \text{-->} 3CO_2 + 4H_2O$$

$$H_2 + 1/2O_2 \text{-->} H_2O$$

The combined calculated tail gas flow rates (based on measured feed rates to the Claus Unit), measured incinerator fuel flow rate, and calculated incinerator combustion air flow rates are used to calculate the SRU Incinerator stack flow rate.

Daily average Claus Unit feed rates and SRU Incinerator fuel feed rates are used to calculate SRU Incinerator exhaust flow rates.

Calculation 2: Plant 2 SRU Incinerator SO_2 Concentration

The SRU Incinerator is equipped with a certified SO_2 CEMS that measures and reports stack SO_2 concentrations in terms of parts per million (volume) at stack O_2 concentrations. This value is used calculate the SO_2 loading in the SRU Incinerator exhaust as follows:

Lbs of SO_2 /Mscf from SRP = [SRU Incinerator SO_2 concentration (scf SO_2/1,000,000 scf exhaust at stack O_2)] [1,000,000 scf / 1,000 Mscf] [1 lbmole SO_2 / 359.04 scf SO_2] [64 lb SO_2 / lbmole SO_2]

Where:

359.04 = Standard molar volume (ft3/lbmole)

A daily average concentration (ppm) from the SO_2 CEMS is used in the above equation to calculate SO_2 loading in the SRU Incinerator exhaust.

<u>Calculation Method for Annual Emissions</u>

For the purpose of calculating SO_2 emissions for the SRP, for use in monitoring compliance with rolling 12-month and calendar year emission limits and for APEN purposes, the calculation method is as follows:

Tons SO_2/12 month period = $\sum$ [Tons of SO_2/month] for current month plus preceding 11 months

Where:

Tons SO_2/year = SO_2 ton/year, rolling 12-month total

Tons SO_2 /month = [Sum of daily emissions for the days in the month]

Refinery Flares

Refinery flares include the sources listed in Table 2-3. Emissions of SO_2 from flares are derived from the combustion of the pilot gas, any sweep or flare system purge gasses, and the combustion of the flared material resulting from process malfunctions or startup and shutdown activities (e.g. acid gases or sour hydrocarbon streams), excess refinery fuel gas), or other reliefs to the flare. For the Plant 2 Truck Dock, Plant 2 MP, #3 Crude Unit, Plant 1 MP Flares, and the Plant 1 Truck Rack, the pilot fuel gas is city gas. For the Plant 1 Rail Rack flare and the Plant 2 Rail Car Dock flare, the pilot fuel gas is propane. A detailed description of each flare is presented below.

Plant 1 Main Plant Flare

The SO_2 emissions from the Plant 1 MP Flare will be calculated based on the flare pilot gas and the volume of gas combusted and the H_2S content in the flared gas. The volume of gas combusted in the Plant 1 MP Flare is continuously monitored. The H_2S concentration of flared gas is obtained approximately once per week using grab samples that are subsequently analyzed on-site in the Refinery laboratory. Other flared gas streams, such as acid gases or sour hydrocarbon streams from malfunctions, startups, or shutdowns, that have short durations may not be properly accounted for by the periodic flare gas H_2S grab-samples since they may start and stop entirely between two samples. When such an event occurs, SO_2 emissions from these events will be estimated based on existing test data, engineering judgment, or process knowledge and will be calculated on a case-by-case basis. Records of the calculation of these case-by-case emissions will be retained on site for Division review.

Calculation Method for Daily Emissions

For the purpose of calculating daily SO_2 emissions for the Plant 1 MP Flare for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method for routine operations is as follows:

$$\frac{\text{lb } SO_2 \text{ from flared gas (lb)}}{\text{day}} + \frac{\text{lb } SO_2 \text{ from pilot fuel (lb)}}{\text{Day}} = \frac{\text{lb } SO_2}{\text{day}}$$

The volume of gas combusted in the flare is calculated based on the measured flared gas velocity in the main flare header. The point at which the velocity measurement is taken is downstream of all connections to the flare header, therefore the velocity measurement is considered to be representative of the flared gas flow rate. The main flare header is 24 inches in diameter. The actual flare gas flow rate is calculated as follows:

$$\frac{\text{Velocity (ft)}}{\text{sec}} \times \frac{\text{86,400 sec}}{\text{day}} \times \frac{3.142 \text{ ft}^2}{1{,}000 \text{ ft}^3 \text{ / Mcf}} = \frac{\text{Flow (Mcf)}}{\text{day}}$$

Where

Velocity (ft/min) = Measured flare gas velocity in flare gas header

86,400 = seconds per day

3.142 ft^2 = Cross-sectional area of 24 inch flare header

1,000 = ft^2/Mcf

Flow (Mcf/day) = Actual flare gas flow rate at process temperature and pressure.

The flow is corrected for pressure and temperature to standard conditions as follows.

$$\frac{\text{Flow (Mcf)}}{\text{day}} \times \frac{519.67\ \text{R}}{\text{Temp (F)} + 459.67} \times \frac{\text{Press (psia)}}{14.696\ \text{psia}} = \frac{\text{Flow (Mscf)}}{\text{day}}$$

Where

Flow (Mcf/day) = Actual flare gas flow rate at process temperature and pressure.

519.67 R = 60 F (standard temperature)

Temp (F) = Process temperature in Fahrenheit

459.67 R = conversion factor converting Temp (F) to Temp (R)

Press (psia) = Process pressure

14.696 psia = Standard temperature

Flow (Mscf/day) = Flare gas flow rate at standard temperature and pressure.

The mass of SO_2 emitted as a result of the combustion of flared gas is calculated as follows:

$$\frac{\text{Flow (Mscf)}}{\text{day}} \times \frac{H_2S\ \text{conc (ppm)}}{1} \times \frac{0.169\ \text{lb}\ SO_2}{\text{ppm}\ H_2S - 1{,}000\ \text{Mscf flare gas}} = \frac{\text{lb}\ SO_2\ \text{from flared gas}}{\text{day}}$$

Where:

Flow (Mscf/day) = Flare gas flow rate at standard temperature and pressure.

H_2S concentration = Measured concentration of H_2S in the flare gas header (ppm, by volume) from periodic sampling

lb SO_2/day = lb of SO_2/day from combustion of flared gas.

The H_2S content in the flared gas is measured once per week by grab sample analyzed using a GC. For the purpose of this daily emissions calculation, the concentration is assumed to be constant during a given sample interval. The flare gas content will be analyzed and compared to facility operations to determine whether or not the most recent sample is representative of actual flare gas composition. This analysis will be conducted using best engineering judgment and detailed process knowledge. Records of any engineering analyses will be retained and included in the monthly records demonstrating compliance with the emission limit.

If, for example, the most recent flare gas sample was taken during a period where the measured H_2S concentration was low (possibly due to a high hydrogen concentration, effectively diluting the H_2S) but current operations are known to have a higher H_2S concentration (possibly due to a reduction in hydrogen being sent to the flare gas system), an engineering analysis will be performed to assess whether or not the next planned flare sample could be considered more representative of some or all of the time period preceding that sample.

The mass of SO_2 emitted as a result of the combustion of the pilot gas is calculated as follows:

$$\frac{3.24 \text{ Mscf}}{\text{day}} \times \frac{0.55 \text{ grains total sulfur}}{0.1 \text{ Mscf}} \times \frac{1 \text{ lb } SO_2}{3{,}500 \text{ grains sulfur}} = \frac{0.006 \text{ lb } SO_2 \text{ from pilot gas}}{\text{day}}$$

Where:

3.24 Mscf/day = pilot gas flow rate to the flare

0.55 grains total sulfur / 0.1 Mscf = Estimated actual total sulfur concentration

1 lb SO_2/3,500 grains sulfur = (1 lb sulfur / 7,000 grains sulfur) x (64 lb SO_2 / 32 lb sulfur)

lb SO_2/day = lb of SO_2/day from combustion of pilot gas.

The Refinery does not currently perform routine monitoring of the incoming city gas total sulfur content. Based on information supplied by Xcel Energy (see Appendix A), the actual total sulfur content is approximately 0.25 to 0.55 grains sulfur per 0.1 Mscf. The upper end of the sulfur content range (i.e. 0.55 grains sulfur per 0.1 Mscf) is used to be conservative. A fixed pilot gas flow rate of 3.24 Mscf/day (3 pilots at 45 scfh each) is based on the design of the flare system.

If a process malfunction or startup/shutdown event results in material being sent to flare that is known to have an H_2S content in excess of the sampled measured value, the unit engineers and operations staff estimate the amount of flared material and the concentration of H_2S in the flared material using the best engineering data available at the time. Due to measurement uncertainties in the flare gas flow rates resulting from the wide range of possible flare flows, engineering assessments will be used rather than measured flare flows. These engineering assessments will be based on data obtained for the specific process unit affected by the process malfunction or startup/shutdown event. This allows for a greater degree of accuracy in calculating overall SO_2 emissions due to a particular event. The estimated mass of SO_2 emitted during this scenario is reported in the "Malfunction Emissions" category.

If there are two or more flaring events in a given day, the Refinery may either separately calculate emissions for each event based on the flow rate and H_2S concentration for that event, or it may utilize the highest H_2S concentration determined for any flaring event on that day to calculate emissions for the day. Refinery staff will record and maintain records regarding the bases for, and exercise of, engineering judgment using the guidelines provided in Section 6.0 of this document.

Calculation Method for Annual Emissions

The Plant 1 MP Flare is not subject to a rolling 12-month SO_2 emission limit. To calculate SO_2 emissions from the Plant 1 MP Flare for APEN purposes, the calculation method is as follows:

Tons SO_2 /year = ∑ [Tons of SO_2/month] for January through December of the reporting year

Where:

Tons of SO_2 /month = [Sum of daily emissions for the days in the month]

Daily emissions = routine emissions + malfunction emissions (if applicable)

Regarding calendar year limits for APEN reporting purposes, the above calculation is performed for the 12 months in the calendar year (January through December) per CAQCC Regulation No. 3, Part A, § II.B.6.

Plant 2 Main Plant Flare

.The SO_2 emissions for the Plant 2 Main Plant Flare will be calculated based on the volume of gas combusted and the monitored sulfur content in the combusted gas. The volume of gas combusted in the Plant 2 Main Plant Flare is monitored by a flow indicator. The H_2S concentration of flared refinery fuel gas is monitored continuously by an H_2S monitor.

Calculation Method for Daily Emissions

For the purpose of calculating daily SO_2 emissions for the Plant 2 Main Plant flare for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method for routine operations is as follows:

$$\frac{\text{lb } SO_2 \text{ from flared gas (lb)}}{\text{day}} + \frac{\text{lb } SO_2 \text{ from pilot fuel (lb)}}{\text{Day}} = \frac{\text{lb } SO_2}{\text{day}}$$

The volume of gas combusted in the flare is calculated based on the measured flared gas velocity in the main flare header. The point at which the velocity measurement is taken is downstream of all connections to the flare header, therefore the velocity measurement is considered to be representative of the flared gas flow rate. The main flare header is 24 inches in diameter. The actual flare gas flow rate is calculated as follows:

$$\frac{\text{Velocity (ft)}}{\text{sec}} \times \frac{86{,}400 \text{ sec}}{\text{day}} \times \frac{3.142 \text{ ft}^2}{1{,}000 \text{ ft}^3 / \text{Mcf}} = \frac{\text{Flow (Mcf)}}{\text{day}}$$

Where

Velocity (ft/min) = Measured flare gas velocity in flare gas header

86,400 = seconds per day

3.142 ft^2 = Cross-sectional area of 24 inch flare header

1,000 = ft^2/Mcf

Flow (Mcf/day) = Actual flare gas flow rate at process temperature and pressure.

The flow is corrected for pressure and temperature to standard conditions as follows.

$$\frac{\text{Flow (Mcf)}}{\text{day}} \times \frac{519.67\text{ R}}{\text{Temp (F)} + 459.67} \times \frac{\text{Press (psia)}}{14.696\text{ psia}} = \frac{\text{Flow (Mscf)}}{\text{day}}$$

Where

Flow (Mcf/day) = Actual flare gas flow rate at process temperature and pressure.

519.67 R = 60 F (standard temperature)

Temp (F) = Process temperature in Fahrenheit

459.67 R = conversion factor converting Temp (F) to Temp (R)

Press (psia) = Process pressure

14.696 psia = Standard temperature

Flow (Mscf/day) = Flare gas flow rate at standard temperature and pressure.

The mass of SO_2 emitted as a result of the combustion of flared gas is calculated as follows:

$$\frac{\text{Flow (Mscf)}}{\text{day}} \times \frac{H_2S\text{ conc (ppm)}}{1} \times \frac{0.169\text{ lb }SO_2}{\text{ppm }H_2S - 1{,}000\text{ Mscf flare gas}} = \frac{\text{lb }SO_2\text{ from flared gas}}{\text{day}}$$

Where:

Flow (Mscf/day) = Flare gas flow rate at standard temperature and pressure.

H_2S concentration = Measured concentration of H_2S in the flare gas header (ppm, by volume) from periodic sampling

lb SO_2/day = lb of SO_2/day from combustion of flared gas.

The mass of SO_2 emitted as a result of the combustion of the pilot gas is calculated as follows:

$$\frac{3.24\ \text{Mscf}}{\text{day}} \times \frac{0.55\ \text{grains total sulfur}}{0.1\ \text{Mscf}} \times \frac{1\ \text{lb}\ SO_2}{3{,}500\ \text{grains sulfur}} = \frac{0.006\ \text{lb}\ SO_2\ \text{from pilot gas}}{\text{day}}$$

Where:

3.24 Mscf/day = pilot gas flow rate to the flare

0.55 grains total sulfur / 0.1 Mscf = Estimated actual total sulfur concentration

1 lb SO_2/3,500 grains sulfur = (1 lb sulfur / 7,000 grains sulfur) x (64 lb SO_2 / 32 lb sulfur)

lb SO_2/day = lb of SO_2/day from combustion of pilot gas.

Calculation Method for Annual Emissions

For the purpose of calculating SO_2 emissions for the main refinery flare for comparison with rolling 12-month and calendar year emission limits and for APEN purposes, the calculation method is as follows:

Tons SO_2/year = ∑ [Tons SO_2 /month] for the current month plus the 11 preceding months

Tons SO_2 /month = [Sum of daily emissions for the days in the month]

Where:

Daily emissions = routine emissions + malfunction emissions (if applicable)

#3 Crude Unit Flare

The SO_2 emissions from the #3 Crude Unit flare will be calculated based on the flare pilot gas and the volume of gas combusted and the H_2S content in the flared gas. As described in Section 2.3, under normal operating conditions, #3 Crude Unit-derived process gases are not directed to the #3 Crude Unit flare, instead a sweep gas flow of city gas continuously purges the #3 Crude Unit flare system. The sweep gas flow rate is manually set at 1,700 scfh and this flow rate is maintained at all times the #3 Crude Unit is operational.

Should a process malfunction occur in the #3 Crude Unit that results in process gasses being sent to the #3 Crude Unit flare, emission estimates will be based on engineering judgment and calculated on a case-by-case basis.

Calculation Method for Daily Emissions

For the purpose of calculating routine daily SO_2 emissions for the #3 Crude Unit flare for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method is as follows:

$$\frac{\text{lb } SO_2 \text{ from flared sweep gas (lb)}}{\text{Day}} + \frac{\text{lb } SO_2 \text{ from pilot fuel (lb)}}{\text{day}} = \frac{\text{lb } SO_2}{\text{day}}$$

The mass of SO_2 emitted as a result of the combustion of flared sweep gas is calculated as follows:

$$\frac{\text{40.8 Mscf}}{\text{day}} \text{ x } \frac{\text{0.55 grains total sulfur}}{\text{0.1 Mscf}} \text{ x } \frac{\text{1 lb } SO_2}{\text{3,500 grains sulfur}} = \frac{\text{0.06 lb } SO_2}{\text{day}}$$

Where:

40.8 Mscf/day = sweep gas flow rate to the flare

0.55 grains total sulfur / 0.1 Mscf = Estimated actual total sulfur concentration

1 lb SO_2/3,500 grains sulfur = (1 lb S / 7,000 grains sulfur) x (64 lb SO_2 / 32 lb sulfur)

lb SO_2/day = lb of SO_2/day from combustion of sweep gas.

The refinery does not currently perform routine monitoring of the incoming city gas total sulfur content. Based on information supplied by Xcel Energy (see Appendix A), the actual total sulfur content is approximately 0.25 to 0.55 grains sulfur per 0.1 Mscf. The upper end of the sulfur content range (i.e. 0.55 grains sulfur per 0.1 Mscf) is used to be conservative.

The mass of SO_2 emitted as a result of the combustion of the pilot gas is calculated as follows:

$$\frac{\text{1.2 Mscf}}{\text{day}} \text{ x } \frac{\text{0.55 grains total sulfur}}{\text{0.1 Mscf}} \text{ x } \frac{\text{1 lb } SO_2}{\text{3,500 grains sulfur}} = \frac{\text{0.002 lb } SO_2}{\text{Day}}$$

Where:

1.2 Mscf/day = pilot gas flow rate to the flare

0.55 grains total sulfur / 0.1 Mscf = Estimated actual total sulfur concentration

1 lb SO_2/3,500 grains sulfur = (1 lb S / 7,000 grains sulfur) x (64 lb SO_2 / 32 lb sulfur)

lb SO_2/day = lb of SO_2/day from combustion of pilot gas.

The Refinery does not currently perform routine monitoring of the incoming city gas total sulfur content. Based on information supplied by Xcel Energy (see Appendix A), the actual total sulfur content is approximately 0.25 to 0.55 grains sulfur per 0.1 Mscf. The upper end of the sulfur content range (i.e. 0.55 grains sulfur per 0.1 Mscf) is used to be conservative. A fixed pilot gas flow rate of 1.2 Mscf/day is based on the design of the flare system (50 scfh). Emissions from the #3 Crude Unit flare are included (assuming 24-hours of operation at the design sweep and pilot gas flow rates) if the average daily thermocouple temperature at the flare tip exceeds 100 degrees Fahrenheit. Neither pilot or sweep gas flow rates are monitored on a real-time basis and this temperature threshold allows for the possibility that the #3 Crude Unit flare will be shutdown for maintenance or a turnaround and would not be emitting SO_2 during that period.

If a process malfunction or startup/shutdown event results in material being sent to the #3 Crude Unit flare, the unit engineers and operations staff estimate the amount of flared material and the concentration of H_2S in the flared material using the best engineering data available at the time. Due to measurement uncertainties in the flare gas flow rates resulting from the wide range of possible flare flows, engineering assessments will be used rather than measured flare flows. These engineering assessments will be based on data obtained for the specific process unit affected by the process malfunction or startup/shutdown event. This allows for a greater degree of accuracy in calculating overall SO_2 emissions due to a particular event. The estimated mass of SO_2 emitted during this scenario is reported in the "Malfunction Emissions" category.

If there are two or more flaring events in a given day, the Refinery may either separately calculate emissions for each event based on the flow rate and H_2S concentration for that event, or it may utilize the highest H_2S concentration determined for any flaring event on that day to calculate emissions for the day. Refinery staff will record and maintain records regarding the bases for, and exercise of, engineering judgment using the guidelines outlined in Section 6.0 of this document.

Calculation Method for Annual Emissions

The #3 Crude Unit flare is not subject to a rolling 12-month SO_2 emission limit. To calculate SO_2 emissions from the #3 Crude Unit flare for APEN purposes, the calculation method is as follows:

Tons SO_2 /year = $\sum$ [Tons of SO_2/month] for January through December of the reporting year

Where:

Tons of SO_2 /month = [Sum of daily emissions for the days in the month]

Daily emissions = routine emissions + malfunction emissions (if applicable)

Regarding calendar year limits for APEN reporting purposes, the above calculation is performed for the 12 months in the calendar year (January through December) per CAQCC Regulation No. 3, Part A, § II.B.6.

Plant 1 Truck Rack Flare

The SO_2 emissions from the Plant 1 Truck Rack flare will be calculated based on the flare pilot gas and on estimates of the volume of gas combusted and the H_2S content in the flared gas. Because Plant 1 Truck Rack flared gas flow rates are not monitored, for purposes of estimating SO_2 emissions from this source for this document, the maximum design flare gas flow rate is conservatively assumed during all periods. In actuality, the average flare gas flow rate will be less than the peak design capacity over a 24-hour period since the flare only operates during loading operations, therefore this approach is considered to be conservative (i.e. over-predictive of SO_2 emissions).

The H_2S concentration of the flared gas is based on the results of the Alternative Monitoring Plan (AMP) justification provided to the APCD on December 21, 2001 and approved by EPA on February 7, 2002 for the Plant 1 Rail Rack flare system. H_2S concentrations in the flared gas stream were measured during a two-week period. The average concentration of H_2S over this two-week period was 1.4 ppm (by volume). Because the products loaded at the Plant 1 Rail Rack are similar to the products loaded at the Plant 1 Truck Rack, and because the materials are limited to the same sulfur content specifications, this estimate is assumed to be representative for the Plant 1 Truck Rack flare system.

<u>Calculation Method for Daily Emissions</u>

For the purpose of calculating daily SO_2 emissions for the Plant 1 Truck Rack flare for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method is as follows:

$$\frac{\text{lb } SO_2 \text{ from flared gas (lb)}}{\text{day}} + \frac{\text{lb } SO_2 \text{ from pilot fuel (lb)}}{\text{day}} = \frac{\text{lb } SO_2}{\text{day}}$$

The mass of SO_2 emitted as a result of the combustion of flared gas is calculated as follows:

$$\frac{1{,}386 \text{ Mscf}}{\text{day}} \times \frac{1.4 \text{ ppm } H_2S}{1} \times \frac{0.169 \text{ lb } SO_2}{\text{ppm } H_2S - 1{,}000, \text{ Mscf FG}} = \frac{0.328 \text{ lb } SO_2}{\text{day}}$$

Where:

(58 Mscf / hr) x (24 hours / day) = maximum design rate assumed to be the flared gas flow rate to the flare

1.4 ppm H_2S = Average concentration of H_2S in the flare header as previously measured (ppm by volume)

lb SO_2/day = lb of SO_2/day from combustion of flared gas.

The volume of gas combusted in the flare is assumed to be equal to the design peak flow rate for the flare system of 1,386 Mscf/day (approximately 7,200 gallons of treated vapor per minute). The flare is conservatively assumed to operate at this peak flow rate for the entire 24-hour period. In the event that the Plant 1 Truck Rack Flare system does not operate for an entire day, the portion of facility emissions estimated from this source will be excluded on that day. If the flare operates for only a portion of the day, the flare will be conservatively assumed to operate for the duration of the day.

The mass of SO_2 emitted as a result of the combustion of the pilot gas is calculated as follows:

$$\frac{2\ \text{Mscf}}{\text{day}} \times \frac{0.55\ \text{grains total sulfur}}{0.1\ \text{Mscf}} \times \frac{1\ \text{lb } SO_2}{3{,}500\ \text{grains sulfur}} = \frac{0.003\ \text{lb } SO_2}{\text{Day}}$$

Where:

2 Mscf/day = Pilot gas flow rate to the flare (Mscf/day)

0.55 grains total sulfur/0.1 Mscf = Estimated actual total sulfur concentration

1 lb SO_2/3,500 grains sulfur = (1 lb S / 7,000 grains sulfur) x (64 lb SO_2 / 32 lb sulfur)

lb SO_2/day = lb of SO_2/day from combustion of pilot gas.

The volume of pilot gas combusted in the flare is assumed to be equal to the design pilot gas flow rate for the flare system of 2 Mscf/day (2 pilots, each burning 43 scfh). The flare pilot is conservatively assumed to operate for the entire 24-hour period. In the event that the Plant 1 Truck Rack flare is not operational for an entire day, the portion of facility emissions estimated from this source will be excluded on that day. If the pilot operates for only a portion of the day, the pilot will be conservatively assumed to operate for the full day.

The Refinery does not currently perform routine monitoring of the incoming city gas total sulfur content. Based on information supplied by Xcel Energy (see Appendix A), the actual total sulfur content is approximately 0.25 to 0.55 grains sulfur per 0.1 Mscf. The upper end of the sulfur content range (i.e. 0.55 grains sulfur per 0.1 Mscf) is used to be conservative.

Due to the nature of the operations at the Truck Rack, the Plant 1 Truck Rack Flare would not have startup/shutdown or malfunction emission events that impact SO_2 emissions (i.e. the truck rack flare cannot accept vapor streams that do not originate from loading operations).

Calculation Method for Annual Emissions

The Plant 1 Truck Rack flare is not subject to a rolling 12-month SO_2 emission limit. For the purpose of calculating SO_2 emissions from the Plant 1 Truck Rack flare for APEN purposes, the calculation method is as follows:

Tons SO_2 /year = $\sum$ [Tons of SO_2/month] for January through December of the reporting year

Where:

Tons of SO_2 /month = [Sum of daily emissions for the days in the month]

Regarding calendar year limits for APEN reporting purposes, the above calculation is performed for the 12 months in the calendar year (January through December) per CAQCC Regulation No. 3, Part A, § II.B.6.

Plant 2 Truck Dock Flare

The SO_2 emissions for the Plant 2 Truck Dock Flare will be calculated based on the volume of gas combusted and the concentration of H_2S in the combusted gas. The volume of combusted gas is based on the volume of product loaded. H_2S concentrations are measured periodically by Colorimetric tube in accordance with an EPA/CDPHE-approved AMP (see Appendix B). The most recent measured H_2S concentration will be used. If the approved AMP is rescinded, the average measured H_2S concentration will still be used. The truck loading operation includes a vapor recovery system that captures the vapors displaced by filling truck tanks with petroleum product. These captured vapors are combusted in the Plant 2 Truck Loading Dock Flare. The products being loaded are gasoline and diesel. Both gasoline and diesel contain a small amount of sulfur. Refinery fuel gas is used for assist gas and pilot fuel.

Calculation Method for Daily Emissions

For the purpose of calculating daily SO_2 emissions for the Truck Dock Flare for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method is as follows:

Lb SO_2 per day = [Lb SO_2 per day from loading (calc. 1)] + [Lb SO_2 per day in fuel combusted in flare (calc 2)]

Calculation 1: lb SO_2 from loading = [MMBtu/day from loading vapor combusted in flare] [MMscf/450 MMBtu] [Conc H_2S, ppm] [lbmole /379 scf gas] [64 lb SO_2/lbmole H_2S]

Where:

MMBtu/day from loading vapor combusted in flare = [[lb/day vapor flared from loading] [Btu/lbs vapor loaded]] /1,000,000

Lb/day vapor flared from loading = [[lb/day vapor from product loading] – [lbs per day vapor not captured]] [0.98]

Lb/day vapor from loading product = [8.15 lb/thousand gal product loaded] [thousand gallons of product loaded per day]

8.15 lbs/thousand gal product loaded = loading losses from AP-42, 1995 Edition, page 5.2-4; 12.46 SPM/T, where S = 0.6, P = 10.9 psia, M = 58 lb/lbmol, and T = 580 °R.

Thousand gallons of product loaded per day = gallons of product loaded per day divided by 1000

Lb/day vapor not captured = [lbs per day vapor from product loading] [1- 0.99]

0.99 = capture efficiency of vapor capture system

0.98 = combustion efficiency of truck dock flare

Btu/lb vapor combusted = 19,000 Btu/lb, based on combustion of N-butane

Conc H_2S, ppm = concentration of H_2S in the gas (2 ppm) based on previous H_2S monitoring data.

Calculation 2: Lb SO_2 per day from fuel combusted in flare = [HR, scf/day] [scf/1,000,000] [conc H_2S, ppm] [0.169, lb SO_2/scf H_2S]

Where:

Lb SO_2 per day from fuel combusted in flare = lb of SO_2/day from combustion of gas used as assist and pilot fuel in flare

Conc H_2S, ppm = concentration of H_2S in the gas (in ppm) from H_2S CEM

0.169, lb SO_2/scf H_2S = [lbmole H_2S/379 scf] [1 lbmole SO_2/1 lbmole H_2S] [64 lbs SO_2/lbmole SO_2]

scf/Btu is measured

The volume of assist and pilot gas combusted is metered

Due to the nature of the operations at the Plant 2 Truck Dock, the Plant 2 Truck Dock Flare would not have startup/shutdown or malfunction emission events that impact SO_2 emissions (i.e. the Truck Dock Flare cannot accept vapor streams that do not originate from loading operations).

Calculation Method for Annual Emissions

For the purpose of calculating SO_2 emissions for the truck dock flare for comparison with rolling 12-month and calendar year emission limits and for APEN purposes, the calculation method is as follows:

Tons SO_2/year = $\sum$ [Tons SO_2 /month] for the current month plus the 11 preceding months

Tons SO_2 /month = [Sum of daily emissions for the days in the month]

Regarding calendar year limits, the above calculations are performed for the 12-months in the calendar year.

Plant 1 Rail Rack Flare

The SO_2 emissions from the Plant 1 Rail Rack flare will be calculated based on the flare pilot gas and estimates of the volume of gas combusted and the H_2S content in the flared gas. Because Plant 1 Rail Rack flared gas flow rates are not monitored within the Refinery data management system, for purposes of estimating SO_2 emissions from this source for the SO_2 caculation methodology, the maximum design flare gas flow rate is conservatively assumed during all periods. In actuality, the average flare gas flow rate will be less than the peak design capacity over a 24-hour period since the flare only operates during loading operations, therefore this approach is considered to be conservative (i.e. over-predictive of actual SO_2 emissions).

The H_2S concentration of the flared gas is based on the results of AMP justification provided to the APCD on December 21, 2001 for the Plant 1 Rail Rack flare system (see Appendix B). H_2S concentrations in the flared gas stream were measured during a two-week period. The average concentration of H_2S over this two-week period was 1.4 ppm (by volume). EPA Region 8 approved the implementation of this plan and required no additional monitoring as long as products subject to sulfur specifications continue to be loaded at the facility.

Calculation Method for Daily Emissions

For the purpose of calculating daily SO_2 emissions for the Plant 1 Rail Rack flare for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method is as follows:

$$\frac{\text{lb } SO_2 \text{ from flared gas (lb)}}{\text{day}} + \frac{\text{lb } SO_2 \text{ from pilot fuel (lb)}}{\text{day}} = \frac{\text{lb } SO_2}{\text{day}}$$

The mass of SO_2 emitted as a result of the combustion of flared gas is calculated as follows:

$$\frac{673.8 \text{ Mscf}}{\text{day}} \times \frac{1.4 \text{ ppm } H_2S}{1} \times \frac{0.169 \text{ lb } SO_2}{\text{ppm } H_2S - 1{,}000 \text{ Mscf FG}} = \frac{0.159 \text{ lb } SO_2}{\text{Day}}$$

Where:

673.8 Mscf / day = maximum design rate assumed to be the flared gas flow rate to the flare

1.4 ppm H_2S = Average concentration of H_2S in the flare header as previously measured (ppm by volume)

lb SO_2/day = lb of SO_2/day from combustion of flared gas.

The volume of gas combusted in the flare (673.8 Mscf/day) is assumed to be equal to the design peak flow rate for the flare system (3,500 gallons per minute of treated vapors). The flare is conservatively assumed to operate at this peak flow rate for the entire 24-hour period.

The mass of SO_2 emitted as a result of the combustion of the pilot gas is calculated as follows:

$$\frac{1.2 \text{ Mscf}}{\text{day}} \times \frac{174 \text{ ppm } H_2S}{1} \times \frac{0.169 \text{ lb } SO_2}{\text{ppm } H_2S - 1{,}000 \text{ Mscf FG}} = \frac{0.035 \text{ lb } SO_2}{\text{Day}}$$

Where:

1.2 Mscf/day = pilot gas flow rate to the flare (Mscf/day)

174 ppm H_2S = Equivalent H_2S content for commercial grade propane

1 lb SO_2/3,500 grains sulfur = (1 lb S / 7,000 grains sulfur) x (64 lb SO_2 / 32 lb sulfur)

lb SO_2/day = lb of SO_2/day from combustion of pilot gas.

The volume of pilot gas combusted in the flare is assumed to be equal to the design pilot gas flow rate for the flare system. A fixed pilot fuel gas flow rate of 1.2 Mscf/day (approximately 50 scfh) is based on the design of the flare system. The flare pilot is conservatively assumed to operate for the entire 24-hour period (midnight to midnight) for which a thermocouple temperature in excess of 100 degrees Fahrenheit was recorded. Neither pilot or sweep gas flow rates are monitored on a real-time basis and this temperature threshold allows for the possibility that the Plant 1 Rail Rack flare will be shutdown for maintenance or a turnaround and would not be emitting SO_2 during that period.

The Refinery does not currently perform routine sulfur content monitoring of the purchased propane fuel used to supply the pilot flame. Based on the American Society for Testing and Materials (ASTM) *"Standard Specifications for Liquified Petroleum Gases"* (D-1835), commercial propane is limited to 185 ppm total sulfur. This corresponds to an equivalent H_2S content of 174 ppm (by volume). Use of the ASTM specification for total sulfur content of commercial propane is considered conservative (i.e. over-predictive) of actual sulfur emissions.

Due to the nature of the operations at the Plant 1 Rail Rack, the Plant 1 Rail Rack Flare would not have startup/shutdown or malfunction emission events that impact SO_2 emissions (i.e. the Plant 1 Rail Rack Flare cannot accept vapor streams that do not originate from loading operations).

Calculation Method for Annual Emissions

The Plant 1 Rail Rack flare is not subject to a rolling 12-month SO_2 emission limit. To calculate SO_2 emissions from the Plant 1 Rail Rack flare for APEN purposes, the calculation method is as follows:

Tons SO_2 /year = ∑ [Tons of SO_2/month] for January through December of the reporting year

Where:

Tons of SO_2 /month = [Sum of daily emissions for the days in the month]

Regarding calendar year limits for APEN reporting purposes, the above calculation is performed for the 12 months in the calendar year (January through December) per CAQCC Regulation No. 3, Part A, § II.B.6.

Plant 2 Rail Car Dock Flare

The SO_2 emissions for the Plant 2 Rail Car Dock Flare will be calculated based on the volume of gas combusted and the concentration of H_2S in the combusted gas. The volume of combusted gas is based on the volume of product loaded. H_2S concentrations are measured periodically by Colorimetric tube in accordance with an EPA/CDPHE-approved AMP (see Appendix B). The most recent measured H_2S concentration will be used. If the approved AMP is rescinded, the average measured H_2S concentration will still be used. The Plant 2 Rail Car Dock Flare is used as a control device during loading of railcars with LPG, gasoline, or low-sulfur diesel fuel. As with the Plant 2 Truck Dock Flare, LPG, gasoline and diesel contain a small amount of sulfur. The volume of gas flared is very low and the SO_2 level in the gas is very low.

Calculation Method for Daily Emissions

For the purpose of calculating daily SO_2 emissions for the Plant 2 Rail Car flare for use in monitoring compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions, the calculation method is as follows:

Lb SO_2/day = [Lb SO_2 /day from loading (calc. 1)] + [Lb SO_2/day from fuel combusted in flare (calc 2)]

Calculation 1: lb SO_2/dayfrom loading = [MMBtu/day from loading vapor combusted in flare] [MMscf/450 MMBtu] [conc H_2S, ppm] [lbmole H_2S/379 scf gas] [64 lb SO_2/lbmole H_2S]

Where:

MMBtu/day from loading vapor combusted in flare = [[lb/day vapor flared from loading] [Btu/lb vapor loaded]] /1,000,000

Lb/day vapor flared from loading = [[lb/day vapor from product loading] – [lb/day vapor not captured]] [0.98]

Lb/day vapor from product loading = [8.15 lbs/thousand gal product loaded] [thousand gallons of product loaded per day]

8.15 lb/thousand gal product loaded = loading losses from AP-42, 1995 Edition, page 5.2-4; 12.46 SPM/T, where S = 0.6, P = 10.9 psia, M = 58 lb/lbmole, and T = 580 °R

Thousand gallons of product loaded per day = gallons of product loaded per day divided by 1000

Lb/day vapor not captured = [lbs per day vapor from product loading] [1- 0.99]

0.99 = capture efficiency of vapor capture system

0.98 = combustion efficiency of Railcar Dock Flare

Btu/lb vapor combusted = 19,000 Btu/lb, based on combustion of N-butane

Conc H_2S, ppm = concentration of H_2S in the gas (2 ppm) based on previous H_2S monitoring data.

Calculation 2: Lb SO_2/day from fuel combusted in flare = [HR, scf/day] [mmscf/1,000,000 scf] [conc H_2S, ppm] [0.169, lb SO_2/scf]

Where:

Lb SO_2/day from fuel combusted in flare = lb of SO_2 from combustion of gas used as pilot fuel in flare

Conc H_2S, ppm = The concentration of H_2S in the propane used for pilot fuel is determined weekly. The most recent monitoring results are used in the calculations

0.169, lb SO_2/scf = [lbmole H_2S/379 scf] [1 lbmole SO_2/1 lbmole H_2S] [64 lb SO_2/lbmole SO_2]

The total volume of pilot gas combusted is metered for the Rail Car Loading Flare

scf/Btu is measured

H_2S of the pilot fuel is measured using a copper strip test to determine if propane meets product quality standards for H_2S. The test is conducted on all spec propane and must be below 10 ppm.

This test gives a less than/greater than 10 ppm result. Suncor will use 10 ppm in this calculation.

Due to the nature of the operations at the Plant 2 Rail Car Dock, the Plant 2 Rail Car Dock Flare would not have startup/shutdown or malfunction emission events that impact SO_2 emissions (i.e. the Plant 2 Rail Car Dock Flare cannot accept vapor streams that do not originate from loading operations).

Calculation Method Annual Emissions

For the purpose of calculating SO_2 emissions for the Plant 2 Rail Car Flare for comparison with rolling 12-month and calendar year emission limit and APEN purposes, the calculation method is as follows:

Tons SO_2/year = $\sum$ [Tons SO_2 /month] for the current month plus the 11 preceding months

Tons SO_2 /month = [Sum of daily emissions for the days in the month]

Regarding calendar year limits, the above calculations are performed for the 12 months in the calendar year.

Malfunction Emissions

In certain malfunction events, SO_2 emissions may be generated that are not quantified in the above-described SO_2 source types. In this case, Refinery engineering, operations, and environmental staff work to determine the quantity of SO_2 that may have been released. These malfunction related emissions are added to the daily total when the malfunction event investigation has been completed. In the case that more than one malfunction occurs on a given day, each malfunction event may be reported separately, or as a combined daily emission estimate. When such an event occurs, SO_2 emissions from these events will be estimated based on existing test data, engineering judgment, or process knowledge and will be calculated on a case-by-case basis. Records of the calculation of these case-by-case emissions will be retained on site for Division review.

Security Emergency Generator Emissions

Emissions of SO_2 resulting from the operation of the generator will be calculated using a mass-balanced based approach that uses fuel input (gallons) and the sulfur specification for ultra-low sulfur diesel (0.0045 wt %). The calculation is shown below.

$$\frac{\text{gallons diesel}}{\text{day}} \times \frac{7.05 \text{ lb diesel}}{\text{gallon}} \times \frac{0.0045 \text{ lb S}}{100 \text{ lbs diesel}} \times \frac{64 \text{ lb } SO_2}{32 \text{ lb S}} = \frac{\text{lb } SO_2}{\text{day}}$$

Soil Vapor Extraction Emissions

Emissions of SO_2 resulting from the operation of a Soil Vapor Extraction system will be calculated assuming that the unit is operating at maximum rated capacity and assumes the use of USEPA AP-42 emission factors for SO_2 (AP-42, Table 3.2-3).

$$\frac{0.006 \text{ lb } SO_2}{\text{MMBtu}} \times \frac{0.6 \text{ MMBtu}}{\text{hr}} \times \frac{\text{hr}}{\text{day}} = \frac{\text{lb } SO_2}{\text{day}}$$

BARRELS OF OIL PROCESSED

The daily Refinery throughput, of barrels per day (bpd) oil charged is determined to calculate compliance with CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limits on SO_2 emissions per barrel oil processed per day. The Refinery total charge rate is based on the amount of crude oil charged to the #1 and #2 Sweet and Sour Crude Units, and purchased intermediate products charged to process units. Examples of purchased intermediates include coker gas oil charged to the #4 HDS or purchased naphtha or gas oils. The barrels of oil processed includes the amount of crude oil and intermediate products charged to the following processes:

1. Charge to the #1 and #3 Crude Units
2. Charge to the #2 Crude Unit
3. Purchased intermediate coker gas oil charge to the #4 HDS
4. Purchased intermediate charge to the #2 Naphtha Hydrotreater/Reformer
5. Purchased intermediate charge to the #2 FCCU
6. Purchased sweet naphtha or gas oil charge to tankage.

For Plants 1 and 3, the charge rates to the two crude units and the #4 HDS (coker gas oil) are continuously metered at one-minute intervals. For purposes of this SO_2 calculati9on methodology, the rates are totaled over a 24-hour period, beginning at midnight.

For Plant 2, the volumes of charge to the Crude Unit, FCCU, and Naphtha Hydrotreater/Reformer, are continuously metered. The volumes of charge are recorded daily.

From time to time, Suncor may purchase intermediate products such as naphtha or gas oil from outside sources. This material will be directed to on-site tankage. Since it will be mixed with intermediates that were produced on-site, it is not possible to directly measure and track the use of these intermediates separately from intermediates produced within the Refinery. These purchases are driven by market conditions, and as such they exhibit a high degree of variability in both timing and size. Suncor will track the use of these purchased intermediates on a case-by-case basis. Examples of how Suncor will track these purchases are provided below.

In the event that a purchase is equal to or less than 1,000 barrels, the entire purchase will be assumed to be charged on the day in which is received.

If a purchase is made that enables a unit to run at a higher rate (i.e. the unit was operating at less than 100% of capacity), the difference between the pre-purchase charge rate and the post-purchase charge rate will be assumed to be the charge rate for the purchased intermediate. For example:

- 10,000 barrels of gas oil are purchased and charged to T-2
- Pre-purchase, the FCCU was operating at 90% of it’s 20,000 bpd capacity
- Post-purchase, the FCCU was operating at 100% of it’s rated capacity.

The difference between 90% and 100% capacity is 2,000 bpd. At 2,000 bpd, the 10,000 barrel purchase will be consumed in 5 calendar days. Therefore for the 5 days following the purchase, the facility charge rate will be increased by 2,000 bpd to reflect the charging of the purchased intermediate product.

Finally, for purchases that do not fit either of the two above scenarios (such as purchases made when the process unit that will eventually receive the purchased intermediate is off-line), the charge rate will be based on process knowledge, operating information, and engineering judgment. For any intermediate purchases, supporting information and calculations will be maintained for APCD review for 5 years.

Suncor will determine the barrels of oil processed and utilize that information as follows:

For purposes of determining compliance with the facility-wide daily emission limit in CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 during routine operations, the average daily amount of oil processed for each calendar month will be determined by adding crude charge for the month plus any intermediate charges, and dividing the total barrels charged for the month by the number of days during the month that any refinery SO_2 source operated. The average daily value for a month shall be calculated by the end of the following month.

COMPLIANCE DEMONSTRATIONS

Regulation No. 1 Daily Emission Limits

For purposes of the CAQCC Regulation No. 1 § VI.B.4.e and Regulation No. 6 § IV.C.2 daily limit on SO_2 emissions per barrel processed per day, SO_2 emissions from each affected source will be calculated for each day. For comparison against the Regulation No. 1 limit, the barrels of oil processed per day will be based on the average daily feed for each calendar month as outlined in Section 4.0 of this document. Daily SO_2 emissions will be divided by the daily average barrels of oil processed for the month. These compliance calculations will be made monthly and will be calculated by the end of the following month. For comparison against the Regulation No. 6 limit, the barrels of oil processed per day will be based on the average daily feed for each calendar year (January 1 through December 31). Daily SO_2 emissions will be divided by the yearly average barrels of oil processed for the year.

Unit or Group Specific Annual Emission Limits

For purposes of calculating rolling 12-month SO_2 emissions for individual or grouped emission units, the annual SO_2 emissions will be calculated on a rolling 12-month basis. Emissions will be calculated for each month, and those emissions will be added to the emissions for the preceding 11 months. The compliance calculation will be made for each month by the end of the following month.

Plant 2 Facility-wide Annual Emission Limit

For the purpose of demonstrating compliance with the Plant 2 facility-wide rolling 12-month SO_2 emission limit, the annual emissions will be determined on a rolling 12-month basis. Emissions will be calculated for each month, and those emissions will be added to the emissions for the preceding 11 months. The compliance calculation will be made for each month by the end of the following month

APEN Reporting

For APEN reporting and fee calculation purposes, annual emissions will be calculated as described in this document. APENs and revised APENs will be based on a calendar year (January through December). These compliance calculations will be made annually. APENs will be submitted to the APCD as required, (currently by April 30th of year after the close of the APEN reporting year if needed).

RECORDKEEPING AND REPORTING PROCEDURES

The purpose of this section is to describe recordkeeping and reporting procedures for the WP and EP SO_2 emissions described in this document.

As outlined in WP Operating Permit Condition 38.1 and EP Operating Permit Condition 22, records of the calculations described in this document, including any case-by-case analyses, will be kept on-site for 5 years.

APENs will be submitted to the APCD by April 30th of year after the close of the APEN reporting year.

Appendix A

Documentation Regarding City Gas Sulfur Content

Xcel Energy℠

ENGINEERING - GAS DELIVERY SERVICES

ASH AND SULFUR CONTENT OF COLORADO AND WYOMING NATURAL GAS

ASH: The ash (non-combustible solid) content of natural gas is zero. However, particulates may form under non-ideal combustion conditions.

SULFUR: The sulfur content of natural gas is reported as hydrogen sulfide (H_2S) and total sulfur (H_2S + all other sulfur-containing compounds). In addition to H_2S, the sulfur-containing compounds include injected odorants (mercaptans and/or organic sulfides), carbonyl sulfide (COS), which is found in some Xcel Energy gas supplies, and naturally occurring mercaptans, which are not commonly found in Xcel Energy natural gas. The Colorado gas tariff limits the H_2S and total sulfur content for shippers who deliver gas onto our pipeline system.

	Tariff Limit for Shippers			**Estimated/Actual Concentration**[1]		
Sulfur Compound	*ppmw*[2]	*ppmv*[2]	gr/Cscf	*ppmw*[2]	*ppmv*[2]	gr/Cscf
Hydrogen Sulfide, H_2S	7[3]	4[3]	0.25[4]	1.7-6.4	1-4[4]	0.05-0.25
Odorant	xx	xx	xx	3.7-7.4	2-4[5]	0.1-0.3
Total Sulfur	143[3]	84[3]	5.0	5-14	3-8	0.25-0.55

NOTES:

1 The actual H_2S and total sulfur of a given supply can only be determined by analysis of samples of that supply.

2 ppmw = parts per million by weight (mass) of sulfur
ppmv = parts per million by volume (mole) of sulfur

Conversion: 1 ppmv = 1.7 ppmw

To convert to %, divide ppm by 10,000: *% = ppm/10,000*

3 Tariff limits for shippers are 0.25 gr H_2S/Cscf (0.235 gr S/Cscf) and 5 gr Total S/Cscf. Standard conditions are 14.73 psia, 60°F.

Conversion: 1 gr S/Cscf = 28.7 ppmw = 17 ppmv

4 The values shown for H_2S are *estimated* average concentrations based on online and spot measurements.

5 Concentrations are based on *actual* odorant injection rates of 0.5-1.0 lb/MMcf. Odorant is mixture of 75% *t*-butyl mercaptan and 25% propyl mercaptans.

Appendix B

Approved Alternative Monitoring Methodologys

Plant 2 Truck Dock Flare and Plant 2 Rail Car Dock Flare

from Colorado Refinery Company and TPI Petroleum Inc. Consent Decree (No. 99-1759) filed September 8, 1999, paragraph IV.7.D et seq., including, without limitation, the requirement to comply with an emission limit, 40 C.F.R. §60.104(a)(1); monitor emissions, 40 C.F.R. § 60.105(a)(3) and (4); make reports and maintain records, 40 C.F.R. § 60.7; and conduct performance testing. 40 C.F.R § 60.8.

(2) Amendment to the Title V Permit Application

The Defendants shall submit to the State of Colorado a proposed amendment to CRC's Title V State of Colorado permit application, which includes the MACT standards for all the loading dock racks, within 30 days of the entry of the Consent Decree.

D. NSPS Subpart J Alternative Monitoring Protocol

Gases combusted in the Truck Loading Dock Flare and LPG Railcar Loading Dock Flare shall be monitored and measurements recorded according to the following alternative monitoring protocol (the "Protocol"), which shall satisfy the requirements of 40 C.F.R. Part 60, Subpart J for monitoring vapors combusted in the Flares during product loading:

(1) CRC/TPI shall conduct one representative measurement during at least one loading event for each Flare during the month in which the Protocol is commenced, on vapors emitted from both the Truck Loading Dock and LPG Railcar Loading Dock during the loading of petroleum products using Drager tubes ("DT") with an appropriate concentration range. For purposes of this Protocol, "loading event" shall mean the

Plant 1 Rail Rack Flare

standard of 162 ppm. Based on: (1) the results of the two weeks of monitoring data, (2) no crossover or entry points between the loading rack and the flare, and (3) the products loaded subject to product specifications, EPA accepts the one time only detection tube monitoring as an alternative monitoring plan for the fuel gas from Conoco's railcar loading rack.

If you have any questions concerning our response to your request, please contact Cindy Reynolds of my staff at (303) 312-6202.

Sincerely,

Martin Hestmark

Martin Hestmark, Director
Technical Enforcement Program

cc: Robert Jorgenson, CDPHE
Shannon McMillan, CDPHE

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Monitoring Schedule

The gas stream consists only of vapors from the railcar loading rack. The products loaded are subject to a product specification for sulfur content. Therefore, one time only detection tube monitoring is sufficient for the Alternative Monitoring Plan. The test data included with this application, combined with this statement that the products loaded are subject to a product specification, meets the requirements for one time only monitoring.

Conoco does not anticipate that the gas stream will change or that the products loaded will no longer be required to meet the product specification for sulfur content. Should either of those events occur, Conoco would resubmit the application for an Alternative Monitoring Plan.